

**FEASIBILITY STUDY OF  
COAL GASIFICATION / FUEL CELL / COGENERATION  
WASHINGTON, D.C. SITE**

**PROJECT DESCRIPTION**

**REPORT CLIN 000301**

**PREPARED FOR**

**DEPARTMENT OF THE ARMY  
AND  
GEORGETOWN UNIVERSITY**

**MAY, 1985**

**EBASCO**

**EBASCO SERVICES INCORPORATED**

Two World Trade Center,

New York, N.Y. 10048

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# TABLE OF CONTENTS

	<u>Page No.</u>
1.0 INTRODUCTION	1
1.1 Overview	2
2.0 SUMMARY	8
2.1 Design Criteria	8
2.2 Overall Plant Description	11
2.3 Plant Performance	14
2.4 Plant Availability	18
2.5 Plant Staffing	21
2.6 Project Schedule	23
2.7 Environmental	25
2.8 References	25
3.0 PLANT GENERAL ARRANGEMENT	26
3.1 Configuration	26
3.2 System Interfaces	32
3.2.1 Electrical	32
3.2.2 Other Site Utilities	33
3.3 Civil	35
3.3.1 Anticipated Site Conditions	35
3.3.2 Design Considerations	36
3.3.2.1 Foundation Support	36
3.3.2.2 Groundwater	36
3.3.3 Construction Considerations	36
3.3.3.1 Soil Excavation	36
3.3.3.2 Rock Excavation	36
3.3.3.3 Existing Foundations	37
3.3.3.4 Backfill and Spoil	37
3.4 References	38
4.0 ELECTRICAL LOADS	39
4.1 Present Load	39
4.2 Future Load	39
5.0 THERMAL LOADS	40
5.1 Present Load	40
5.2 Future Load	42



# TABLE OF CONTENTS (Cont'd)

	<u>Page No.</u>
6.0 SYSTEM DESIGN DESCRIPTION	46
6.1 <u>Material Handling</u>	46
6.1.1 Coal Handling	46
6.1.1.1 Functions and Design Requirements	46
6.1.1.2 System Description	49
6.1.1.3 System Performance	49
6.1.2 Ash Handling	49
6.1.2.1 Functions and Design Requirements	49
6.1.2.2 System Description	50
6.1.2.3 System Performance	50
6.1.2.4 Maintenance	50
6.1.2.5 Technical Risks	51
6.2 <u>Coal Gasification</u>	51
6.2.1 Functions and Design Requirements	57
6.2.2 System Description	59
6.2.3 System Performance	59
6.2.4 Maintenance	61
6.2.5 Technical Risks	62
6.2.6 References	63
6.3 <u>Gas Processing</u>	63
6.3.1 Functions and Design Requirements	63
6.3.2 System Description	79
6.3.3 System Performance	81
6.3.4 Maintenance	82
6.3.5 Technical Risks	84
6.3.6 Natural Gas Standby	85
6.3.7 References	86
6.4 <u>Fuel Cell and Power Conditioner</u>	86
6.4.1 Fuel Cell System	86
6.4.1.1 Functions and Design Requirements	88
6.4.1.2 System Description	97
6.4.1.3 System Performance	97
6.4.1.4 Maintenance	99
6.4.1.5 Technical Risks	

TABLE OF CONTENTS (Cont'd)

	<u>Page No.</u>
6.4.2 Power Conditioner	100
6.4.2.1 Functions and Design Requirements	100
6.4.2.2 System Description	102
6.4.2.3 Maintenance	105
6.4.2.4 Technical Risks	106
6.4.3 References	108
6.5 <u>Thermal Management System</u>	109
6.5.1 Functions and Design Requirements	109
6.5.2 System Description	114
6.5.3 System Performance	121
6.5.4 Maintenance	122
6.5.6 Technical Risks	122
6.6 <u>Auxiliary Systems</u>	123
6.6.7 Electrical	123
6.6.2 Cooling Water System	123
6.6.3 Water Treatment	126
6.6.4 Plant Safety	130
6.6.5 Nitrogen Gas Supply	133
6.6.6 Hydrogen Gas Supply	133
6.6.7 Station and Instrument Air	133
6.7 <u>System Control</u>	135
6.7.1 Introduction	135
6.7.2 Control System Configuration	135
6.7.3 Control Room Layout	137
6.7.4 Control Components and Operation	137
6.7.5 Safety	140
6.7.6 System Control Description	141
6.7.6.1 Coal Gasification	141
6.7.6.2 Gas Cooling, Cleaning and Compression	143
6.7.6.3 Fuel Cell	146
6.7.6.4 Thermal Management System	148

TABLE OF CONTENTS (Cont'd)

	<u>Page No.</u>
7.0 ENVIRONMENTAL	149
7.1 Summary of Emissions	149
7.2 Applicable Laws & Regulations	149
7.2.1 Air	157
7.2.1.1 Federal	157
7.2.1.2 District of Columbia	159
7.2.2 Water	159
7.2.2.1 Federal	159
7.2.2.2 District of Columbia	162
7.2.3 Solid Waste	163
7.2.3.2 Federal	163
7.2.3.2 District of Columbia	164
7.2.4 Other Federal and Local Environmental Requirements	166
7.2.5 National Environmental Policy Act	166
7.3 References	168
8.0 APPENCES	169
A. Equipment List	170
B. Forwarded References	185

# LIST OF FIGURES

<u>Figure</u>		<u>Page No.</u>
2-1	Block Flow Diagram	12
2-2	Project Schedule	24
3-1	Plot Plan, Sheet 1	27
3-1	Plot Plan, Sheet 2	28
3-2	General Arrangement, Sheet 1	29
3-2	General Arrangement, Sheet 2	30
5-1	Steam Flow vs. Month at Georgetown University	41
6.1-1	Coal Handling and Storage Section	47
6.2-1	Coal Gasification Section	52
6.3-1	Gas Cooling, Cleaning and Compression Section	68
6.3-2	CO Shift Section	71
6.3-3	Sulfur Removal and Recovery Section	74
6.3-4	Process Condensate Treatment Section	77
6.4-1	UTC Fuel Cell and Thermal Management Systems	87
6.4-2	Effect of Operating Time on DC Voltage	98
6.4.3	Typical Power Converter Functional Block Diagram	101
6.4-4	Typical Power Converter Schematic	103
6.6-1	Cooling Water System	124
6.6-2	Water Treatment System	128
6.7-1	Control System Functional Block Diagram	136
6.7-2	Operator Interface and Peripherals	138
6.7-3	Control Room Operator's Board	139

# LIST OF TABLES

<u>Table</u>		<u>Page No.</u>
2-1	Site Conditions	10
2-2	System Performance	15
2-3	Overall Energy Balance	17
2-4	Plant Availability	20
2-5	Plant Operator Assignments	22
5-1	Georgetown University Buildings Gross Area of Future Additions and Demolitions	43
5-2	Summary of Gross Areas	44
5-3	Existing and Future Thermal Energy	45
6.2-1	Coal Analysis	54
6.2-2	Raw Gas Composition	55
6.2-3	Gasifier Material Balance	56
6.2-5	Mass Balance - Coal Gasification Section	60
6.3-1	Treated Process Effluent Characteristics	64
6.3-2	Mass Balance - Gas Cooling, Cleaning and Compression Section	69
6.3-3	Mass Balance - CO Shift Section	72
6.3-4	Mass Balance - Sulfur Removal and Recovery Section	75
6.3-5	Mass Balance - Process Condensate Treatment Section	78
6.4-1	Anode Feed Gas Specification	89
6.4-2	Fuel Cell Cooling Water Criteria	90
6.4-3	Mass Balance - Fuel Cell Section	91
6.4-4	Fuel Cell Parameters	93
6.4-5	Power Conditioner Performance Characteristics	107
6.5-1	TMS Process Criteria	112
6.5-2	Mass Balance - Thermal Management System	115
6.6-1	Cooling Water System Loads	125
6.6-2	Fuel Cell Makeup Water	129
7-1	GFC Emissions Versus Regulatory Limits	150
7-2	Estimated Air Emissions	152
7-3	Estimated Water Emissions	153
7-4	Estimated Solid Wastes	154
7-5	Composition of Blowdown from Stretford Process	155

LIST OF TABLES (Cont'd)

<u>Table</u>		<u>Page No.</u>
7-6	Summary of Environmental Requirements	156
7-7	Threshold Emission Levels for Major Modifications	158
7-8	Applicable Requirements of the DC Air Pollution Control Act of 1984	160

The purpose of this report is to describe a Coal Gasification/Fuel Cell/Cogeneration (GFC) project that is specific to the Georgetown University site in Washington, DC.

The project at this site, as with those at the three other sites selected for this program, is intended to demonstrate the technical, economic and financing viability of power generation by fuel cells using gas from coal.

The specific design described in this report is based on a United Technology Corporation nominal 11 MW fuel cell and has evolved from the following two predecessor reports:

1. CLIN 0001 - Basic System Description, March 1985
2. CLIN 000201 - Preliminary Site Survey

Although this report does not include cost estimates or economic and financial analyses, it is intended to form the basis for such information which will be included in forthcoming reports numbered CLIN 0004, CLIN 0005 and CLIN 0006.

Mass and energy balances have been prepared for the gasification, gas processing, fuel cell and thermal management systems using an East Kentucky design bituminous coal, selected for its low tendency to cake in the gasifier bed.

With safety, aesthetic and land use criteria satisfied, this plant will meet federal and local environmental laws and regulations, should have a design/fabrication/construction period of approximately 51 months and have performance characteristics as shown in Table 2-2.

## 1.1 Overview

Section 2.0 of this report discusses design criteria, overall plant description, plant performance, plant availability and required staffing. It then addresses a project schedule that accounts for requirements additional to the basic GFC plant that integrate the total installation with the existing site's physical plant and unique energy needs. These additional requirements are referred to as the "GFC Site Specific Increment" and are described in this section.

Section 3.0 discusses the physical arrangement of the plant as well as the electrical and other utility connections.

Section 4.0 discusses present and future electrical loads and Section 5.0 covers the same for thermal loads.

Section 6.0 entitled, System Design Description, discusses for each of the major systems constituting the GFC, functions and design requirements, system description, system performance, maintenance requirements and technical risks.

Section 7.0 discusses environmental regulations and permitting requirements comparing GFC emissions with regulatory limits.

The following summarizes some of the information described in this report.

### I. GENERAL

- Plant floor area is approximately 90,000 ft<sup>2</sup>;
- Plant is designed around an 11 MW UTC Fuel Cell;
- The Thermal Management System (TMS) is arranged to maximize electrical power production;
- Plant will meet PURPA criteria for recognition as a "Qualifying Facility" (QF).
- Plant design allows for sale of byproducts, decreasing capital expenditures and operating costs;
- GFC emissions will be well below regulatory limits;

- System interfaces: Electrical connection of power output to the PEPCO grid will follow industry guidelines and include any additional PEPCO requirements.

## II. SYSTEM DESIGN DESCRIPTION

### A. Material Handling

1. Coal
  - The function of this system is to receive, weigh, sample, screen, store, convey coal to the gasifiers.
2. Ash
  - The function is to remove ash collected in gasifier storage hoppers

The material handling system requiring only basic maintenance has high reliability and low technical risk.

### B. Coal Gasification

- The function of this system is to derive gas from coal for ultimate use by the fuel cell;
- Performance of the Wellman-Galusha gasifier indicates that it can operate from 8.5% to 111% of its rated capacity of 3 1/2 tons/hr;
- Maintenance is minimal, most of it being performed during the scheduled two week annual shutdown;
- As a system with a long history of successful industrial application, technical risks are minimal.

### C. Gas Processing

- The function of this section is to cool, clean, and compress the gasifier effluent, and then to convert it to a hydrogen-rich, sulfur-free stream, suitable for use by the fuel cell;
- The performance of this section is assessed as satisfactory under full and part load conditions, with variations in flow rate not adversely affecting the gas quality;
- Equipment for this process is selected for maximum reliability and minimum maintenance. Major maintenance is performed during the scheduled annual shutdown;
- Technical risks are assessed as low.

### D. Fuel Cell and Power Conditioner

#### 1. Fuel Cell

- The function of the fuel cell is to convert hydrogen in the gas from the Gas Processing Section into usable electrical, mechanical, and thermal energy;
- The fuel cell operates at about 10% greater efficiency at 50% load than at 100% load. Voltage degrades a little more than 10% over the 40,000 hour life of the cell stacks;
- Maintenance for the expander, compressor and generator is typical of that for rotating equipment. Fuel cell stacks are periodically replaced to maintain minimum voltage level;
- Technical risks include the potential for electrolyte leakage, low cell voltage, catalyst poisoning or coolant fouling. However these problems can be averted through design changes or proper maintenance.

## 2. Power Conditioner

- The function of the Power Conditioner is to convert the dc output of the Fuel Cell to 3 phase ac power for connection to the PEPCO grid. It also regulates the operation of the Fuel Cell so as to maintain the required power output;
- The performance of the Power Conditioner is rated at efficiencies of 90% over the entire operating load range;
- Systems utilizing similar design concepts (e.g. Tokyo Electric Power Co. (TEPCO) 4.5 MW cell) have proven to be reliable in utility related applications.

## E. Thermal Management System (TMS)

- The TMS converts thermal and chemical energy flows discharged from the fuel cell into one or more of following energy forms that can reduce plant operating costs or generate revenue.
  - 1) Steam and electrical power to satisfy GFC system process demands thus lowering plant costs;.
  - 2) Steam for export to satisfy Georgetown's Heating and Cooling Plant (HPC) requirements;
  - 3) Electrical power for export to utilities.
- Georgetown University HCP steam demand is large enough to use all the steam produced. Since this demand is inexpensively satisfied by the existing coal fired Atmospheric Fluidized Bed Boiler Plant (AFB) it was decided as a basis for this study that TMS steam export to the HCP be the minimum necessary to meet PURPA requirements and the remaining steam be used to produce electric power.
- Since the fuel cell efficiency increases as the load decreases, steam production tends to drop more rapidly than does fuel cell power output with a lowering of load.

Maintenance: Equipment for the TMS is of proven reliability which can be sustained through regular maintenance.

Technical risks is minimal, being no more than that normally assumed by commercial ventures in mature technologies.

#### F. Auxiliary Systems

- The auxiliary systems include 1) Electrical for powering auxiliary systems; 2) Water cooling system to dispose of heat from coal gasifiers, gas processing, and the TMS system; and 3) Water treatment to take out impurities in the water incompatible with any step of the process.
- Instrumentation and control system is configured with centralized control and control processors. Each major state of the GFC process has a local subsystem control board located close to the process area.

### III. ENVIRONMENTAL

- This section reviews emissions which will be generated by the Georgetown GFC, discusses the applicable environmental laws and regulations and concludes that the GFC system as constituted requires no extraordinary emission control measures.

### IV. GFC Site Specific Increment

The "GFC Site Specific Increment" assures that the site receiving the fuel cell system has its unique energy requirements fulfilled with no net loss of prior essential assets or facilities.

At Georgetown University the GFC Site Specific Increment includes the following:

1. Compensation for loss of athletic playing areas. This includes relocation of six tennis courts and compensation for displaced land area.

2. Replacement of parking for 970 cars displaced by the GFC plant.

3. Relocation of utilities that now serve the existing site.

Items 1 and 2 above are shown on Figure 3-1.

## 2.0 SUMMARY

### 2.1 Design Criteria

Criteria and design objectives that govern the design and selection of systems, equipment and supporting facilities for the GFC plant are as follows:

#### 1. Plant Availability and Reliability

- a) Maximum plant availability is to be achieved through use where possible, of commercially proven equipment.
- b) Redundancy is to be provided for critical controls and for selected motorized equipment.
- c) Natural gas is considered as a backup fuel. The economics of adding the gas service, methane reformer, hydrodesulfurizer, gas compressor and accessories will be reviewed in forthcoming report, CLIN 0004.
- d) Coal storage is to provide a minimum of six days GFC operation at plant maximum continuous rating.

- 2. Plant is designed around the UTC 11 MW nominal output fuel cell.
- 3. Plant is to operate baseloaded with the Thermal Management System designed to maximize electrical power generation rather than steam export.
- 4. System operation is to be based on maximum automation and centralized control.
- 5. Plant is to be capable of meeting federal and local environmental requirements.
- 6. Most plant components are to be factory fabricated and pressembled for truck delivery.

7. The GFC plant must meet the Georgetown University aesthetic criteria, typical for a prominent university with an urban campus.
8. The GFC plant must displace a minimum of useable natural campus land area, including lawns and playing fields and must stay within prescribed height limits.
9. Access roads for coal delivery, ash removal and for other vehicles serving the facility, must not interfere with normal traffic flow of the university.
10. Construction operations must minimize the effect on the normal operation of the university and must not adversely affect existing structures.
11. Safety criteria and regulations must be complied with, including those governing hydrogen, carbon monoxide and sulfuric acid.
12. Plant must provide suitable access for fire department vehicles and personnel.
13. Plant must meet Public Utilities Regulatory Policies Act (PURPA) criteria to be classified as a "Qualifying Facility" (QF).
14. Plant site conditions are as summarized in Table 2-1.

TABLE 2-1

SITE CONDITIONS<sup>(1)</sup>

Elevation Above Mean Sea Level, ft	14
Design Atmospheric Pressure, psia	14.76
Summer Outdoor Design Temperatures, °F <sup>(2)</sup>	
(Dry Bulb)/(Mean Coincident Wet Bulb)	93/75
Winter Outdoor Design Dry Bulb, °F <sup>(3)</sup>	14
Summer Outdoor Design Wet Bulb, °F <sup>(4)</sup>	78
Summer Indoor <sup>(6)</sup> Design Dry Bulb, °F	105
Winter Indoor <sup>(6)</sup> Design Dry Bulb, °F	55
Annual Heating Degree Days, Average <sup>(5)</sup>	4224

Notes:

1. Technical Manual TM-5-758, engineering Weather Data, July 1, 1978, Department of the Army, p. 111, Data for Washington DC National Airport.
2. Dry bulb equaled or exceeded 1% of time on the average during the warmest four consecutive months.
3. Dry bulb equaled exceeded 99% of time on the average for the coldest three months.
4. Used for cooling tower design: Wet bulb exceeded 1% of time on the average during the warmest four consecutive months.
5. 30 year average for 65°F base.
6. Unairconditioned spaces.

## 2.2 Overall Plant Description

Layouts indicate that approximately 90,000 ft<sup>2</sup> of floor area is required for the GFC system. Of this, 58,000 ft<sup>2</sup> for the gas bearing portions of the system is open to the atmosphere through a multi-tier arrangement of gratings with the remainder in a ventilated below grade enclosure. (Refer to paragraph 3.1). The tallest structures are the Wellman-Galusha gasifier and the saturator (T-201). Including the bucket elevator, the gasifier is 80'-0" above the base slab at 70' elevation. The saturator (T-201) in the Gas Cooling Section is 70' high.

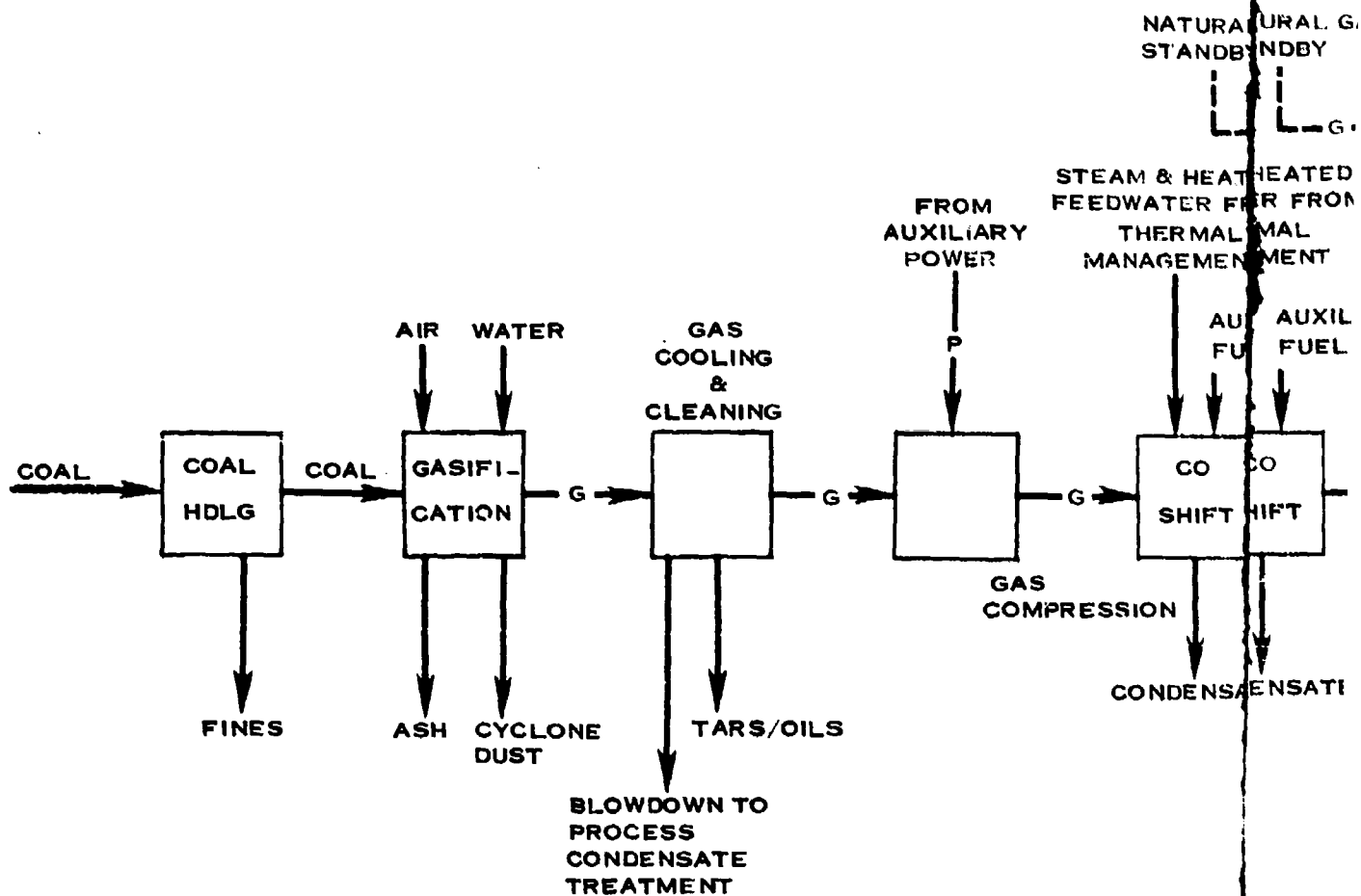
This system is based on the UTC fuel cell and has a nominal gross electrical output of 11.6 MW.

2000 lb/hr of cogenerated steam at 230 psia is after reduction to 105 psia, supplied to the main campus heating system.

A conceptual view of the base system design is given by the block flow diagram of Figure 2-1. The process starts with truck delivery of coal to new bunkers installed in the open area south of the existing Heating Cooling Plant (HCP). Coal reclaimed from these bunkers is conveyed to the adjacent two Wellman-Galusha gasifiers. Saturated gasification air reacts with the coal in the gasifier, producing hot raw gas and ash. The raw gas is cooled to condense and separate out oils and tars and then compressed to 167 psia.

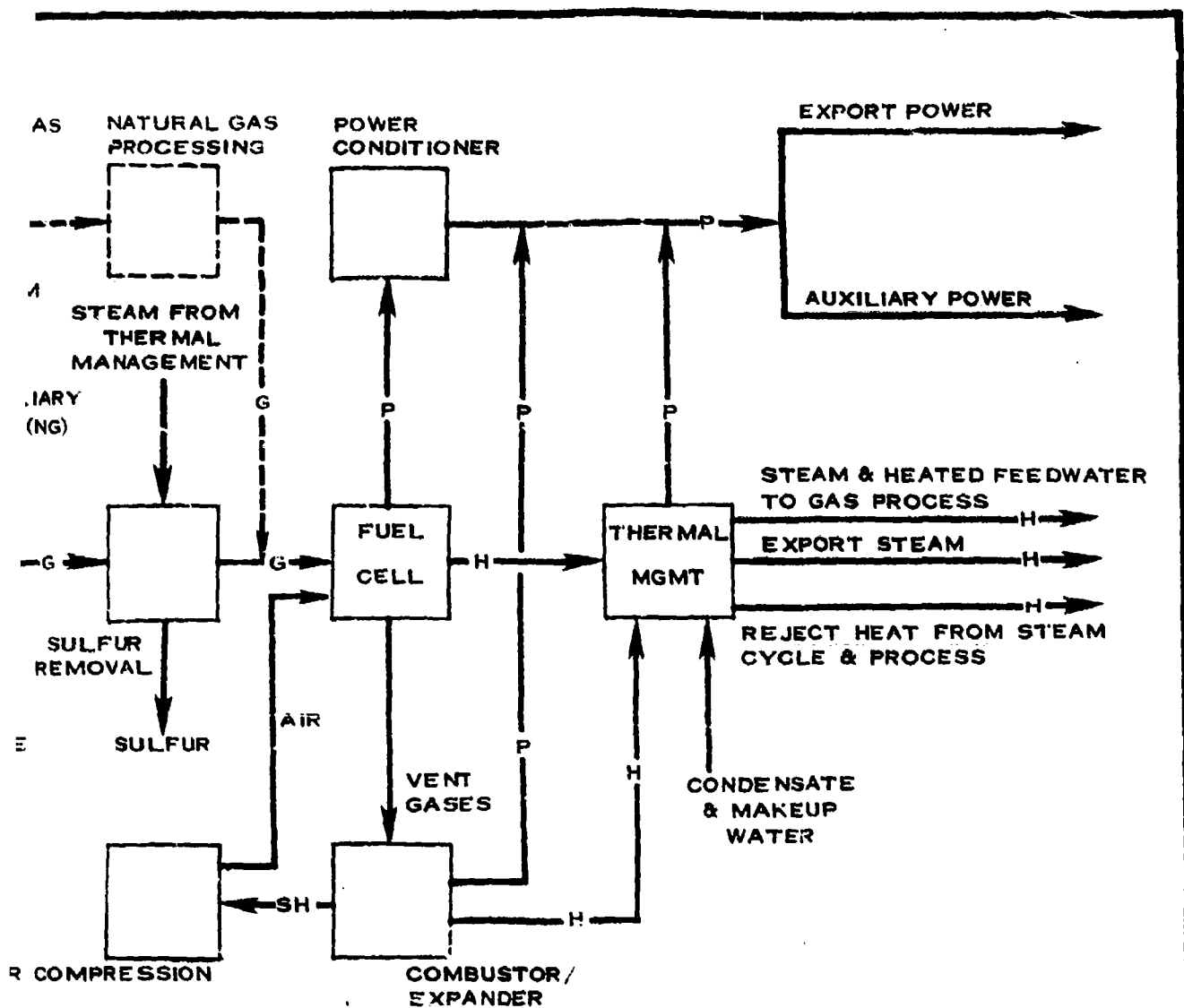
The design for the Washington DC site includes motor driven centrifugal gas compressors which are electrically powered from GFC system output.

Utilizing steam at 230 psia from the CO Shift boiler and from the Thermal Management System, the compressed gas undergoes a CO shift reaction to increase the hydrogen content. The gas is then desulfurized and heated before final polishing and feeding to the fuel cell.



# **SYMBOLS:**

- OPTIONAL
- SH— SHAFT CONNECTION
- P— POWER
- H— HEAT
- G— FUEL GAS



DOA / GEORGETOWN UNIVERSITY
COAL GAS / FUEL CELL / COGENERATION
WASHINGTON D.C. SITE BLOCK FLOW DIAGRAM
FIGURE 2-1
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Receiving compressed fuel gas and air at the anode and cathode respectively, the fuel cell electrochemically converts the energy in the hydrogen and oxygen components of these feed gases to direct current power and heat. The fuel cell power output is then conditioned for use in an AC utility network.

Vent gases from the fuel cell power a combustor/expander which drives the air compressor and a 2500 kW induction motor-generator. This latter equipment is part of the Thermal Management System which receives and "manages" heat from the fuel cell electrochemical reaction, from the combustor/expander and from any process heat source. Byproduct tars and oils are to be sold rather than fired in an onsite boiler.

The design of the Thermal Management System largely determines the magnitude and relative proportions of plant power output and export heat.

For this site, most of the heat received by the Thermal Management System can be used to drive a turbine and synchronous generator of 890 kW capacity.

Also included in the Thermal Management System is a cooling tower and circulating water system that removes approximately  $47 \times 10^6$  Btu/hr of heat rejected from the gas process, from compressor intercoolers and from steam condensers serving the power turbine.

Other systems required to support the facility include fire detection and protection, instrumentation and controls, makeup water treatment, drainage, heating and ventilation of enclosures, freeze protection of equipment and piping, flush water and compressed air and nitrogen for blanketing and purging.

## 2.3 Plant Performance

GFC plant performance is summarized in Table 2-2. In determining the overall efficiency of 43% and a heat rate of 13,250 Btu/kWh, credit was taken for the heat content of tars and oils. Sale of this byproduct will eliminate the capital expenditure, operating cost, space requirement and environmental concerns of a tar/oil boiler plant.

Because coal supplied to the existing heating plant fluidized bed boiler (AFB) is less costly (\$53/ton) than the low Free Swelling Index coal required for the fuel cell (\$62 to \$67/ton), this report favors maximum use of the AFB rather than the fuel cell for steam production. The concomitant decision to emphasize production of electricity with fuel cell cooling system steam and with expander exhaust heat, is reflected in the plant performance summary of Table 2-2.

The Public Utilities Regulatory Policies Act (PURPA) which is administered by the Federal Energy Regulatory Commission (FERC), governs how a cogeneration facility can become a Qualifying Facility (QF).

An important advantage of this QF status is that it mandates purchase at avoided costs by the public utility of electric power produced by the cogenerator.

The operating standard of PURPA requires that a new QF must produce at least 5% of the total energy output as useful thermal energy. The facility heat balance in Section 6.5 satisfies this requirement with a thermal energy percentage of 6.1.

The second standard imposes criteria for minimum operating efficiencies on facilities where oil or gas is the primary fuel and is therefore not applicable to this system.

The remaining requirement states that a utility may not own more than 50% of a cogeneration facility and is also inapplicable.

TABLE 2-2

SYSTEM PERFORMANCE  
(UTC CELL, WASHINGTON, D.C.)

Coal Input to Gasifier <sup>(1)</sup> , Tons/D	172.2
Heating Value of Coal Input <sup>(2)</sup> , Btu/hr	$136.5 \times 10^6$
Fuel Cell Output, MW DC	11.6
Power Conditioner Output, MW AC	11.0
Power from Gas Expander, MW	2.5
Power from Steam Turbine, MW	0.9
Auxiliary Power, MW	3.6
Net Power, MW	10.8
Export Steam @230 psia, lb/hr	2,000
Tar and Oils Heat Content, Btu/hr	$38.7 \times 10^6$
Heat Rate, Btu/KWh <sup>(3)</sup>	13,250
Overall Plant Efficiency, %	43

Notes:

1. Based on maximum of 15% fines in as-received coal.
2. Based on higher heating value of 13000 Btu/lb
3. Takes credit for thermal value of export steam and byproducts.

Based on the above, the performance of the GFC system at Georgetown meets the criteria for classification as a "Qualifying Facility."

The overall energy balance is shown in Table 2-3.

Based on the ability of the gasifier to accept up to 15 percent as fines, all fines are assumed to be usefully consumed.

Of the total system energy loss of  $147 \times 10^6$  Btu/hr, 79 percent occurs in the coal handling, coal gasification and gas processing sections of the GFC system.

Therefore, in the final design of this system, major efforts must be directed to reducing these losses in order to maximize cycle efficiency.

TABLE 2-3  
OVERALL ENERGY BALANCE

Item	Energy (10 <sup>6</sup> Btu/hr)	
	In	Out
Energy in Coal	186.54	
Energy Produced (Gross)		49.25
Fuel Cells	37.54	
Gas Expander Generator	8.67	
Steam Turbine Generator	3.04	
Parasitic Power		(12.24)
Export Steam		2.10
Energy in Byproducts		42.48
Coal Fines	-	
Cyclone Carbon Dust	2.49	
Tars and Oils	38.68	
Ash	1.31	
Heat Rejected by Cooling Tower		47.00
Other Heat Releases to Environment		57.95
CO Shift Air Cooler	14.70	
HRSG Stack Loss	25.20	
Miscellaneous	18.05	
TOTAL	186.54	186.54

## 2.4 Plant Availability

Systems and equipment are to be selected and arranged to provide maximum overall availability and reliability.

Availability for one year operation is defined as

$$A = 1 - \frac{US + PS}{365}$$

and reliability as

$$R = 1 - \frac{US}{365 - PS}$$

where US = Unscheduled Shutdown, days/yr

PS = Planned Shutdown, days/yr

Estimates of the days per year of unscheduled shutdown were developed for the component sections of the GFC and listed in Table 2-4. The fuel cell, power conditioner and Thermal Management System estimate of 22 days unscheduled shutdown per year is based on Reference 2-1. (Within this system group, the power conditioner has a reliability of 98.2 percent which represents 6 days unplanned outage).

In the Gas Cooling and Cleaning Section, the component with most potential for shutdowns was identified as the electrostatic precipitator. Experience with this item indicates a reliability of 99 percent or an unplanned outage of four days.

It may be noted that the Gasification, and Gas Processing Sections contribute an additional 17 days of unplanned shutdown, reducing the plant availability factor from 0.90 for a natural gas fueled plant to 0.85 for a coal gas fueled plant.

Operating as a base loaded plant at an average of 95 percent of maximum continuous rating, the plant capacity factor is 0.81 (= 0.95 x 0.85).

The above estimates apply to a GFC plant only after a sufficient period of "running in" and testing has occurred to eliminate initial operating and design problems. It is estimated that this period could be a year in duration.

TABLE 2-4  
PLANT AVAILABILITY

<u>Unscheduled Shutdown(1)</u>		<u>Days/Yr</u>
Fuel Cell, Power Conditioner, Thermal Management System(2)		22
Gasifier		3
Electrostatic Precipitator		4
CO Shift		1
Stretford Desulfurizer		3
Gas Compressors		3
Material Handling(3)		<u>3</u>
Subtotal		39
<u>Scheduled Shutdown</u>		14
Total Annual Shutdown		53
Plant Reliability	$(1 - 39/(365-14))$	0.89
Plant Availability	$(1 - (39 + 14)/365)$	0.85
Plant Load Factor		0.95
Plant Capacity Factor	$(0.85 \times 0.95)$	0.81

Notes:

1. Refers to complete GFC system shutdown caused by listed item.
2. See Reference 2-1
3. See Reference 2-2

## 2.5 Plant Staffing

An estimate of operator assignments to the various sections of the GFC plant for each of the three working shifts, is given in Table 2-5.

With each letter (A, B, C, etc.) representing one individual, five operators would be on duty at all times.

In addition to the five operators would be a supervisor located in the Control Room.

Considering days off, relief fill in, vacations, training, performance of maintenance tasks and premium payments for weekends and night shifts, a factor of 4.2 is applied to obtain "equivalent operating staff".

The total assigned to the plant is then as follows:

Equivalent Operating Staff (6x4.2)	25
Laboratory Technicians	3
Maintenance/Repair Personnel	3
Plant Manager/Engineer	1
Clerical	<u>2</u>
Total Equivalent Staff	34

TABLE 2-5

PLANT OPERATOR ASSIGNMENTS<sup>(1)</sup>

	<u>Operator</u> <sup>(2)</sup>
Material Handling	A
Gasification	A
Gas Cleaning, Cooling, Compression	B
CO Shift	B
Sulfur Removal & Recovery	B
Process Condensate Treatment	C
Water Treatment	C
Fuel Cell	D
Power Conditioner	D
Thermal Management System	D
Instrumentation and Control Systems	E
Auxiliary System	E

Total Operators = (A+B+C+D+E) = 5

Supervisor 1

Total Operating Staff 6

Notes:

1. Assignments are for a single shift.
2. Each letter (A, B, C, etc.) represents one plant operator.

## 2.6 Project Schedule

The 51-month project schedule shown in Figure 2-2 assumes that compliance with the National Environmental Policy Act (NEPA) will entail the preparation and review of an Environmental Assessment (EA) and not an Environmental Impact Statement (EIS). (If an EIS is required, the NEPA process could take an additional six months or longer.)

It also assumes that the federal and District of Columbia approvals and permits will be available seven months after project start. This in turn permits the start of work on site construction facilities, construction access, earthwork and excavation and allows letting contracts for supply of the longest lead items.

Work on GFC system foundations and structures would commence in excavated areas on the 23rd month with installation of delivered equipment and interconnecting services completed in the 40th month.

UTC's preliminary estimate is that due to the limited capacity of their first manufacturing facility, site delivery would occur roughly 24 months after placement of an order in 1986 or 1987 - depending also upon prior production commitments. This makes the fuel cell/power conditioner package the project's longest lead item.

It therefore becomes necessary to initiate negotiations and place an order for the fuel cells as early in the project as possible. It is estimated that this order or letter of intent can be issued about seven months after start of GFC engineering (11 months after project start) with delivery of the fuel cells occurring in the 35th month. Some typical "order to delivery" time frame estimates by other suppliers are:

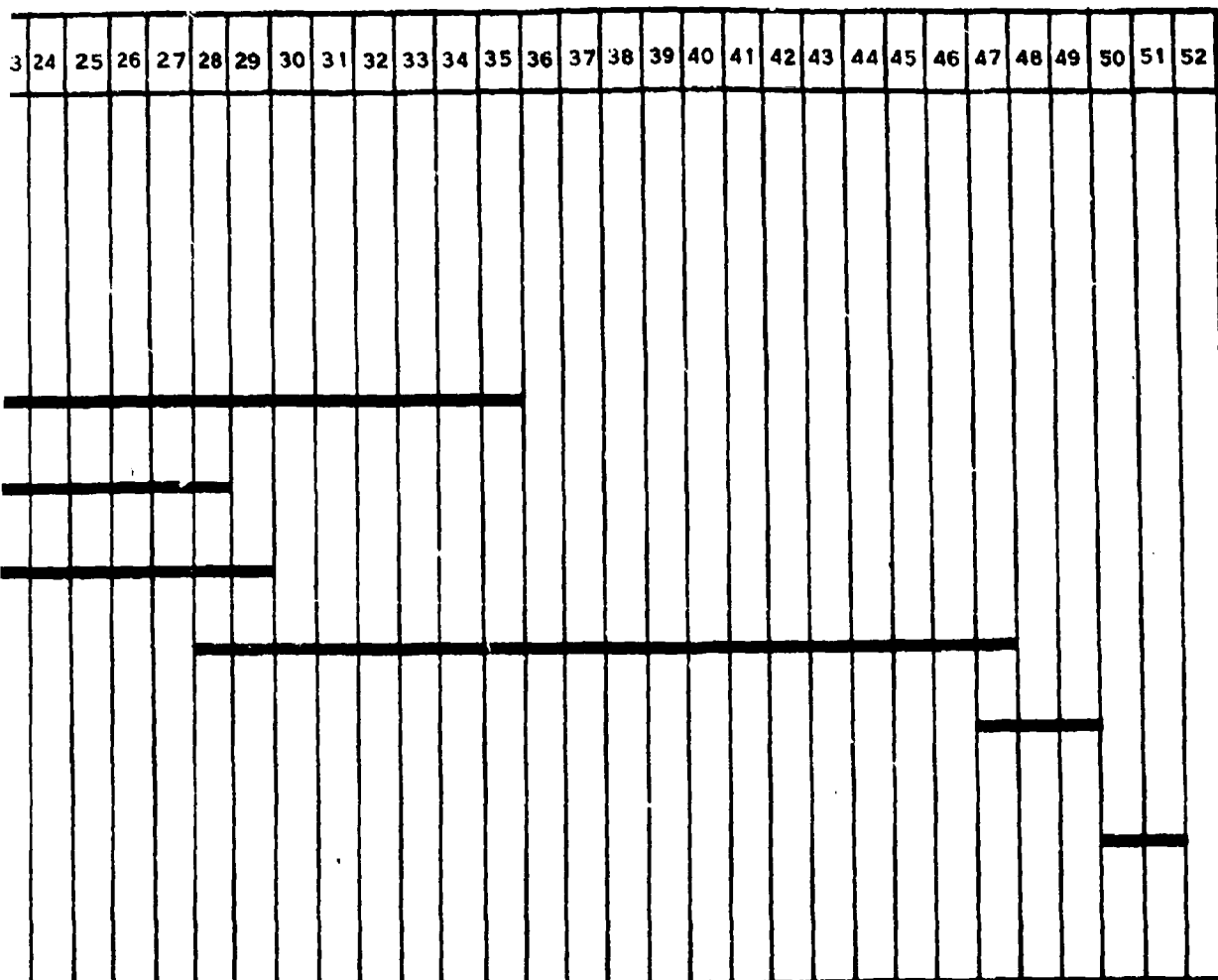
Steam turbine-generator	-	40 weeks
Gas expander - compressor	-	54 weeks
Vessels and towers	-	45 weeks
Gasifiers	-	26 weeks

MONTH FROM																							
TASKS	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
LICENSING & PERMITTING																							
SYSTEM ENGINEERING <sup>(1)</sup>																							
PROCUREMENT <sup>(2)</sup>																							
VENDOR CONTRACT WORK <sup>(3)</sup>																							
DESIGN & CONSTRUCTION <sup>(4)</sup> OF DISPLACED FACILITIES																							
EARTHWORK & EXCAVATION																							
CONSTRUCTION																							
PREOPERATIONAL TESTING & START-UP																							
TRIAL OPERATION																							

**NOTES:**

1. INCLUDES DEVELOPMENT OF SYSTEM DESIGN DRAWINGS, SPECIFICATIONS, BID ANALYSES, REVIEW OF VENDOR SUBMITTALS
2. INCLUDES PROCUREMENT ACTIVITIES UP TO CONTRACT AWARDS
3. INCLUDES VENDOR ENGINEERING, FABRICATION & DELIVERY
4. REFERS TO CONSTRUCTION REQUIRED TO RELOCATE UNIVERSITY FACILITIES TO BE DISPLACED BY FUEL CELL SYSTEM
5. THE START OF ENGINEERING IN 5TH MONTH FOLLOWS A 9 TO 12 MONTH PERIOD FOR PRELIMINARY ENGINEERING AND COAL SAMPLE TESTING.

FROM START



DOA / GEORGETOWN UNIVERSITY  
 COAL GAS/FUEL CELL/COGENERATION  
 WASHINGTON D.C. SITE  
 PROJECT SCHEDULE  
 FIGURE 2-2  
 EBASCO SERVICES INCORPORATED

The fuel cell "order to delivery" time exceeding all those listed above, has the greatest influence on project duration.

The start of engineering in the fifth month follows a 9 to 12 month period for preliminary engineering, the final selection of a gasifier technology and sufficient progress in coal testing to confirm both the raw gas composition and the selection of a design coal. This preliminary phase of work is currently scheduled to start in early 1986 and to be completed by the end of that year.

## 2.7 Environmental

A comparison of GFC plant emissions and the applicable regulatory limits is given in Table 7-1 of Section 7.0.

This table shows air and liquid emissions to be well below regulatory limits. Solid wastes will be disposed of according to requirements of the Resource Conservation and Recovery Act and local laws. Noise will be controlled to meet both University criteria and District of Columbia requirements during construction and during operation.

## 2.8 References

- 2-1 Westinghouse Electric Corp., "Phosphoric Acid Fuel Cell, 7.5 MWe dc Electric Power Plant Conceptual Design," WAESD TR-83-1002, May 1983.
- 2-2 Fluor Power Services, Inc., "Component Failure and Repair Data for Coal-Fired Power Units", EPRI AP-2071, October 1981.

### 3.0 PLANT GENERAL ARRANGEMENT

#### 3.1 Configuration

The Coal Gasification/Fuel Cell/Cogeneration (GFC) plant is located south of the existing Heating and Cooling Plant (HCP).

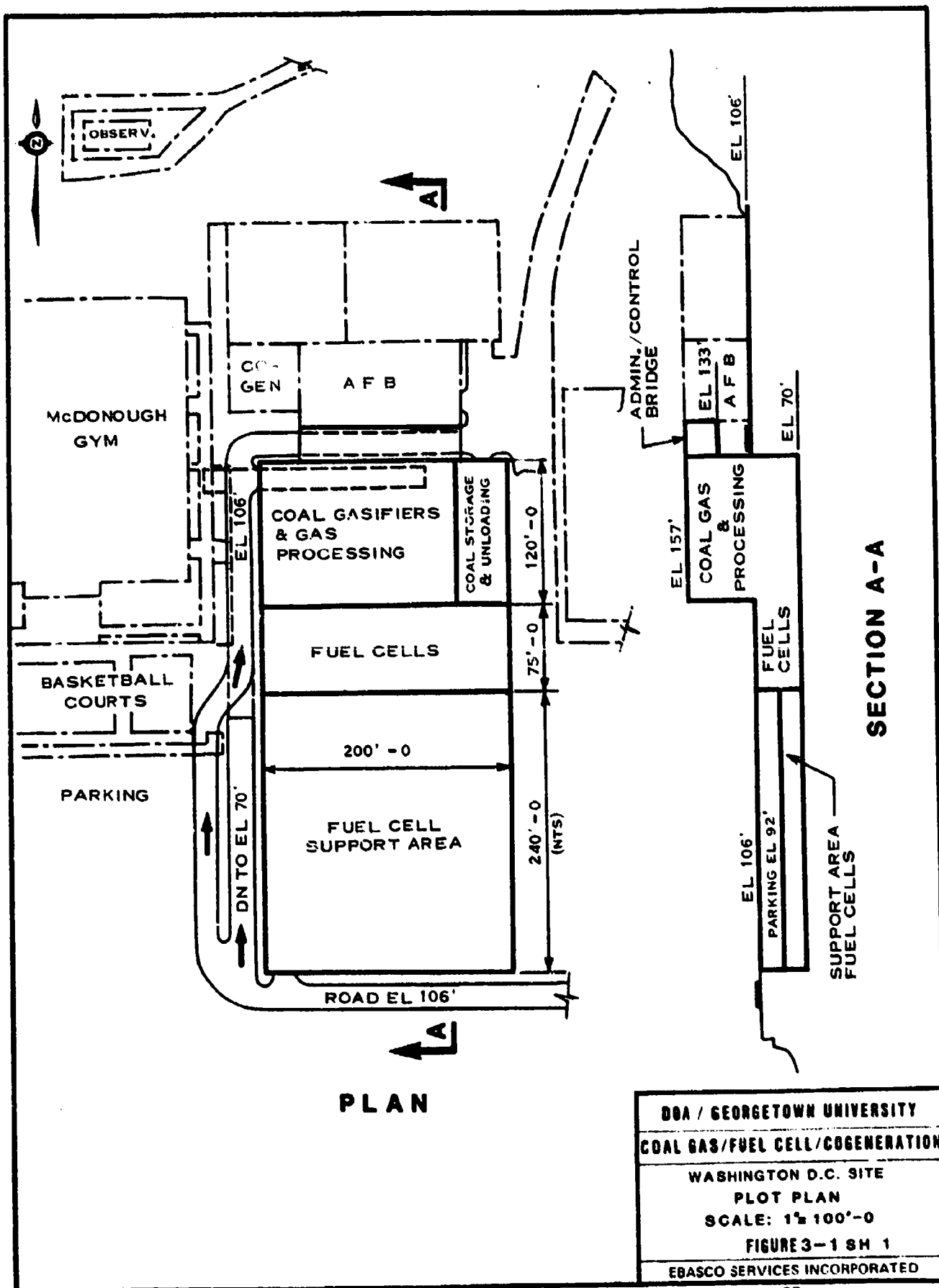
Figure 3-1, Sheets 1 and 2 shows the GFC Plant area. Figure 3-2, Sheets 1 and 2 shows the equipment layout.

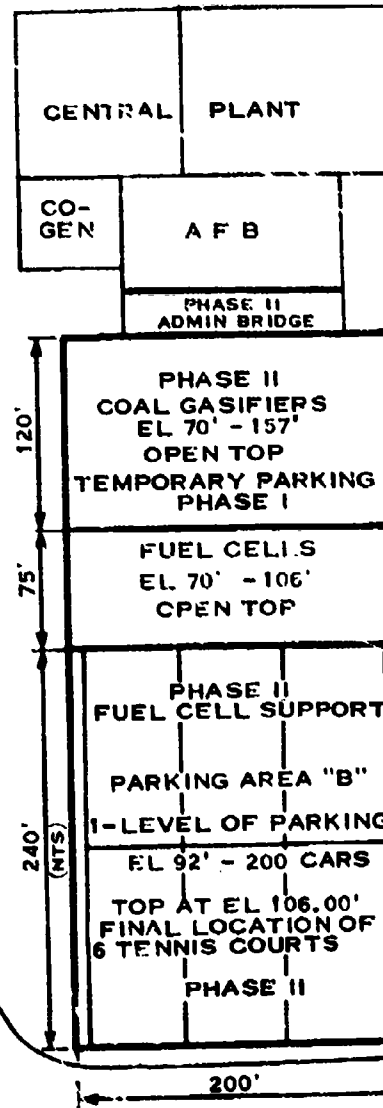
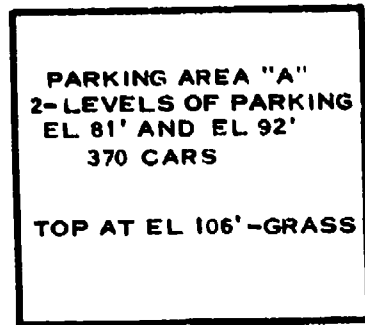
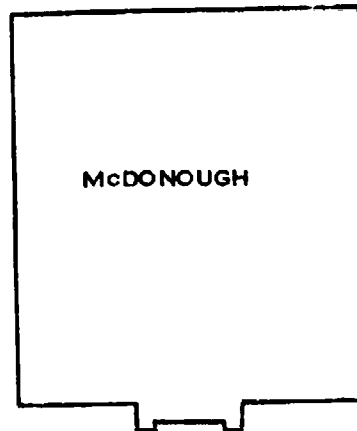
The GFC plant being studied includes one complete 11 MW module which may be followed by a second future module. The module consists of the Coal and Ash Handling Section, Gasification Section, Gas Cooling, Cleaning and Compression Section, CO Shift Section, Sulfur Removal and Recovery Section, Process Condensate Treatment Section and the Fuel Cell and Thermal Management Section and Auxiliary Systems.

The coal gasifiers, the Gas Cooling, Cleaning and Compression Section, the CO Shift Section, some of the equipment from the Process Condensate Treatment Section (the sour water storage tank S-501, pumps P-501 and ammonia stripper T-501) and the Sulfur Removal and Recovery Section are located in a new Gas Processing Building south of the existing HCP. The floor of this building is at elevation 70' and the roof at elevation 157'. The roof which consists of a grating, is open to atmosphere to prevent the concentrating of gases that may leak from the process equipment. As most leakage is expected from the gasifiers, these are separated from the remaining equipment by a "gasifier enclosure". The gas compressor is located in an enclosure for noise control.

Air cooler E-301 which reduces temperature of the fuel gas after the exothermic CO shift reaction, and the main cooling tower are located below the roofline of the Gas Processing Building on a steel framework.

The flare from the ammonia stripper in the Process Condensate Treatment Section and flares from the coal gasifiers are also located near the roof of the Gas Processing Building. The gasifier flares extend 10 feet above the gasifier enclosure roof.





**PLAN**

EL 106' = NOMINAL PRELIMINARY  
ELEVATION

SOCCER FIELD

EXISTING SEWERS - PEDESTRIAN WAY

INTERIM 6 TENNIS COURTS PHASE I

PARKING AREA "C"

3 - LEVELS OF PARKING

EL 70', EL 81' AND EL 92'

400 CARS - TOP AT EL 106' - GRASS

RAMP

PARKING FACILITY  
CONNECTION AT EL 92', 70'

EL 106' - GRASS/LANDSCAPING  
PHASE II

RAMP

N

DOA / GEORGETOWN UNIVERSITY

COAL GAS/FUEL CELL/COGENERATION

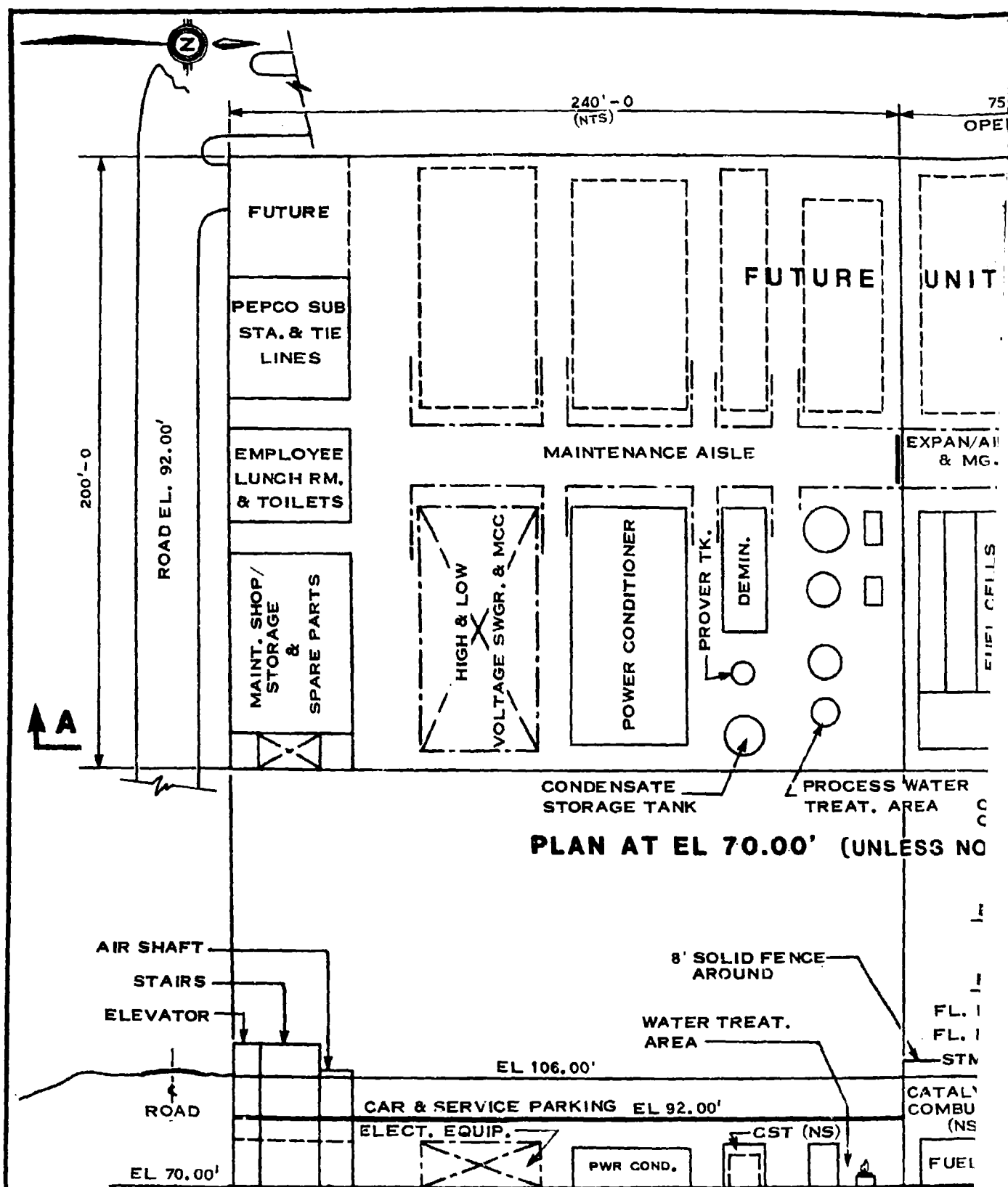
WASHINGTON D.C. SITE

PLOT PLAN

SCALE: 1" = 100'-0"

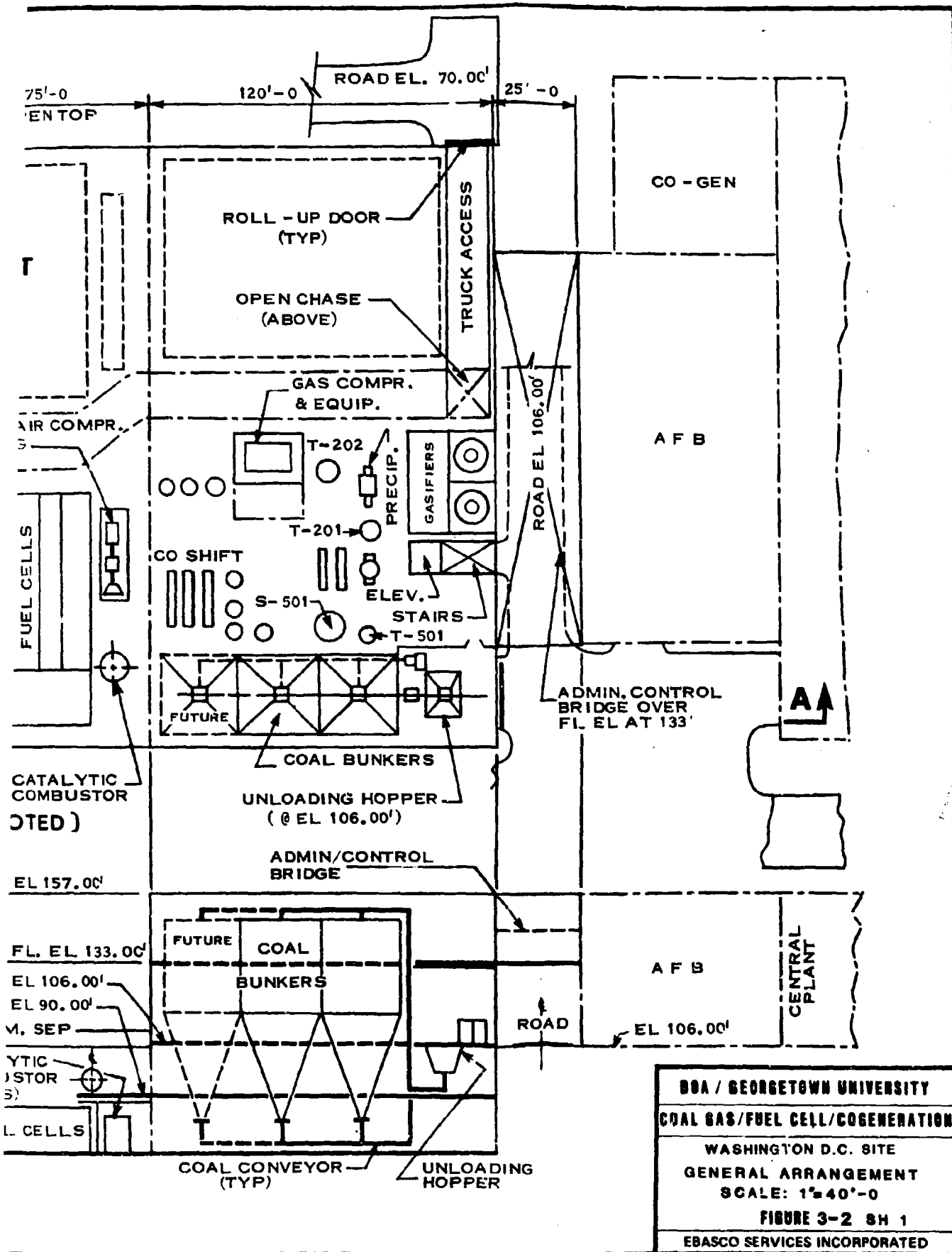
FIGURE 3-1 SH 2

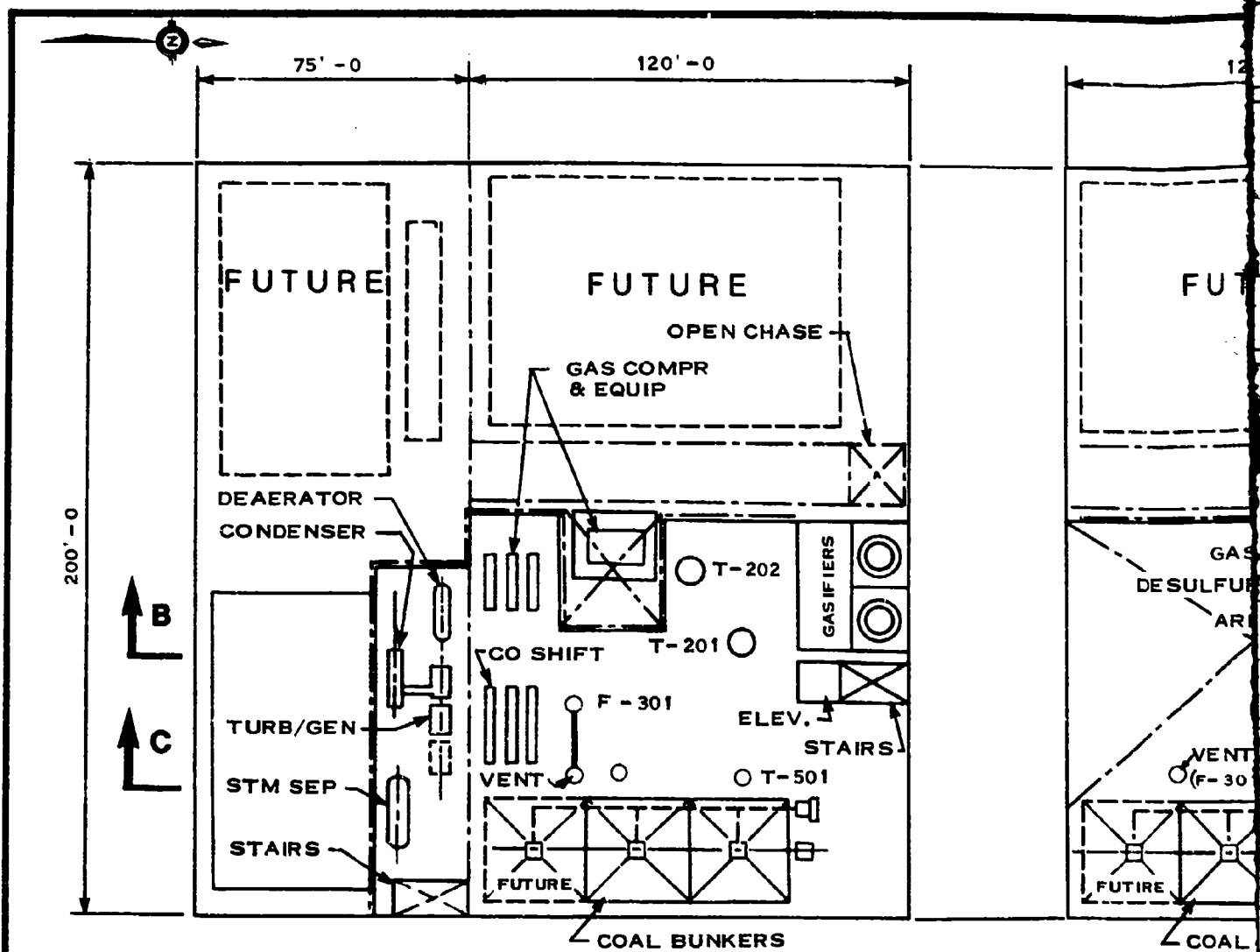
EBASCO SERVICES INCORPORATED



PLAN AT EL 70.00' (UNLESS NO

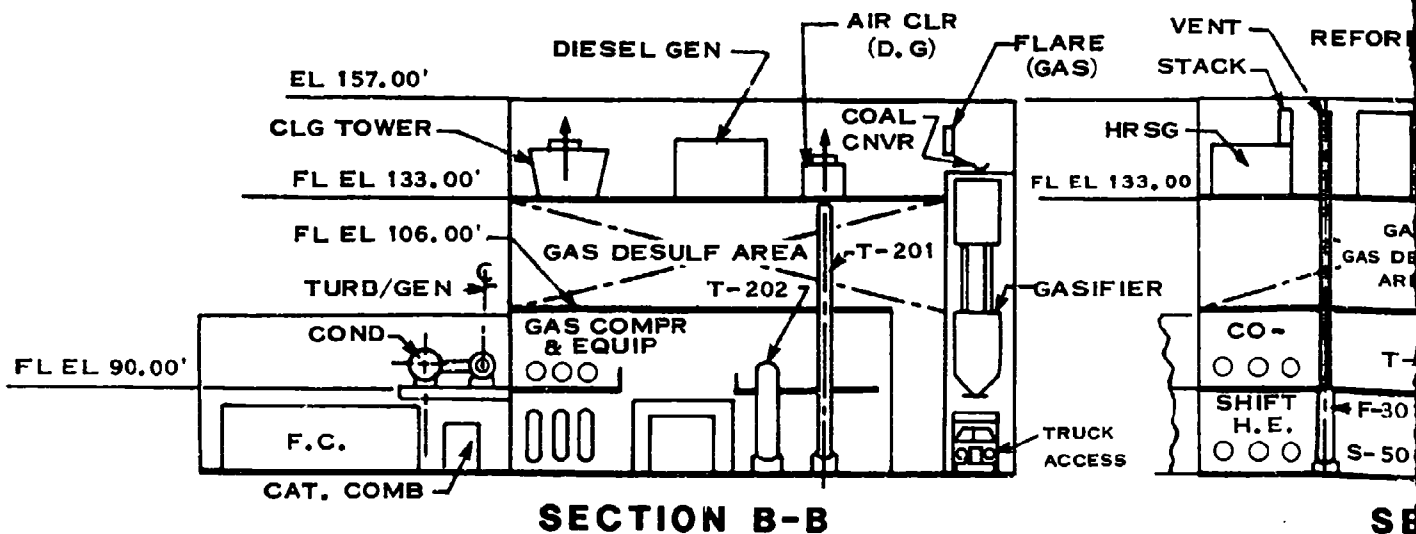
SECTION A-A





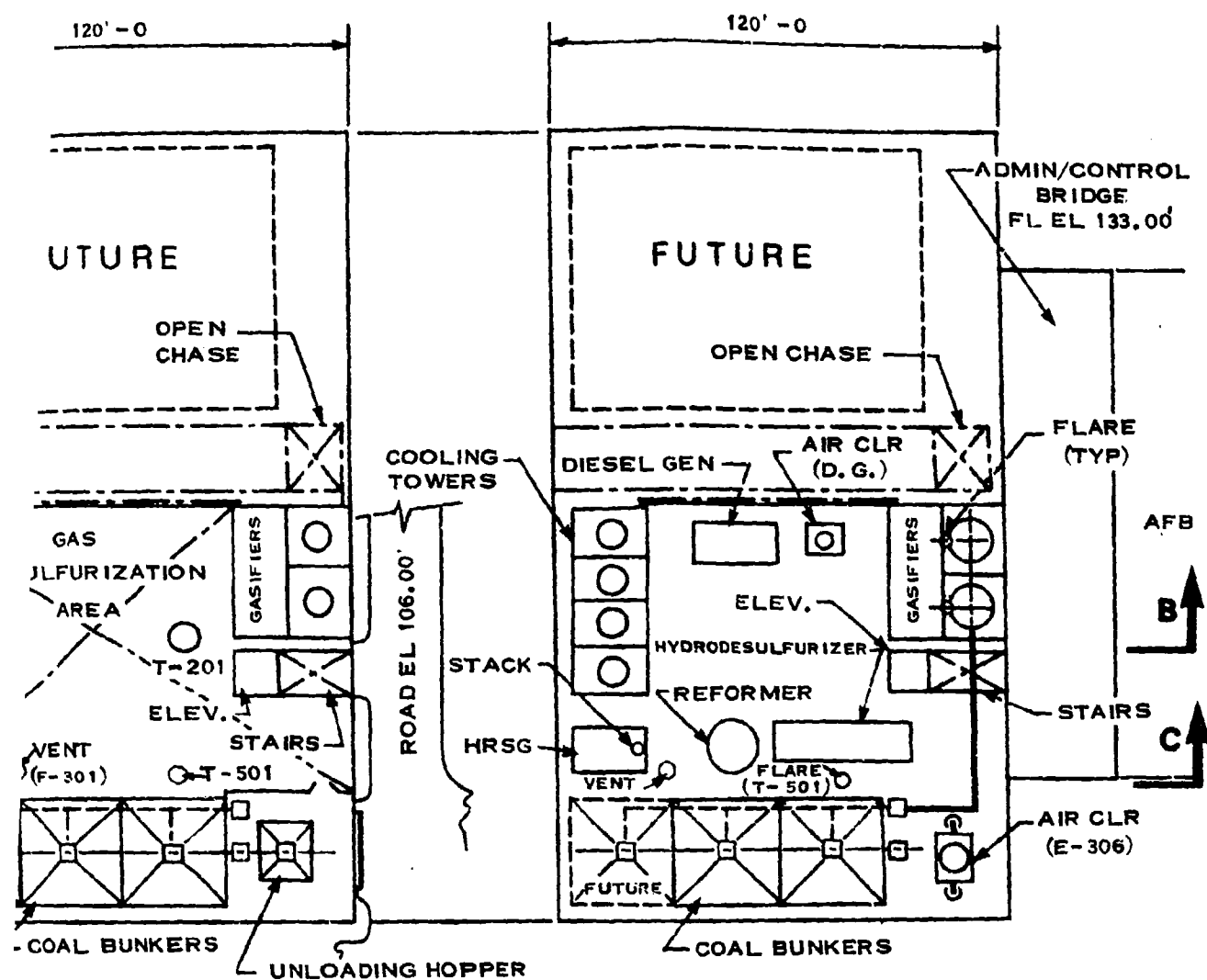
**FLOOR PLAN AT EL 90.00'**

**FLOOR PLAN AT EL 90.00'**

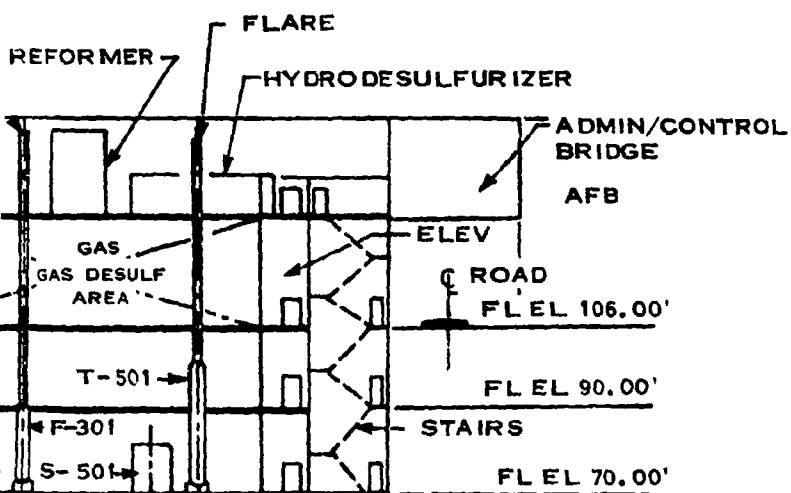


**SECTION B-B**

**SECTION C-C**



**FLOOR PLAN AT EL 106.00' FLOOR PLAN AT EL 133.00'**



**SECTION C-C**

DOA / GEORGETOWN UNIVERSITY
COAL GAS/FUEL CELL/COGENERATION
WASHINGTON D.C. SITE
GENERAL ARRANGEMENT
SCALE: 1"=40'-0"
FIGURE 3-2 8H 2
EBASCO SERVICES INCORPORATED

The Fuel Cell System and a portion of the Thermal Management System are located immediately south of the Gas Processing Building in an enclosure at 70 elevation with top of enclosure consisting of a grating at grade elevation 106'.

To the south of the Fuel Cell enclosure is a 240' x 200' space (for two GFC modules) located at 70' elevation and beneath one level of parking garage at 91' elevation. This space includes equipment and systems that do not contain coal gas or hydrogen and includes such items as the following:

- Power Conditioners
- Transformers
- Switchgear and Motor Control Centers
- Process Condensate
- Water Treatment
- Repair Shop
- Parts Storage
- Material Storage
- Lockers

There are two (2) coal bunkers located in the Gas Processing Building serving the GFC plant. If a second future GFC module is installed one more bunker will be added. Coal is delivered to these bunkers at the east wall of the Gas Processing Building (See Paragraph 6.1).

The contents of the gasifier ash hoppers and gasifier cyclone hoppers are unloaded directly into a truck on a daily basis for off-site dumping. Ramp access to the gasifier hoppers is provided.

All equipment is fully accessible from floors or platforms and arranged with adequate space for operation, maintenance and repairs. Adequate laydown space and lifting devices are provided for equipment overhaul.

Approach roads, ramps and aisles are to be designed for equipment removal and replacement by trucks and for access by the fire department.

The Administration and Control Bridge for the GFC will be located between the existing Heating Cooling Plant and the new Gas Processing Building. Access from the bridge to the Gas Processing Building operating floor and main platforms will be by elevator and stairway.

### 3.2 SYSTEM INTERFACES

#### 3.2.1 Electrical

Electrical connection of the GFC system to the Potomac Electric Power Company (PEPCO) grid including protective relaying, generally follows industry guidelines<sup>(1)</sup> and includes any additional PEPCO requirements.

The fuel cell output is connected to the PEPCO system through a static converter which is similar in all respects to those used throughout the power industry for HVDC and variable frequency systems, except that it must be designed to accept the input voltage variations associated with the fuel cell plant.

Statistics<sup>(2)</sup> indicate that availability of HVDC converters averaged 94.6 percent (98.2 percent if maintenance outages are excluded) for the period 1977-1981. The converter is of a 12-pulse design, with filters as required to reduce the harmonic content of power output to the PEPCO system. Harmonic content of the converter output must conform to the requirements of Reference 3. Power components of the converter are conservatively rated to ensure maximum reliability. The converter is completely self protecting against faults and all thyristors are protected against current and voltage surges.

In general, the converter is of modular design for ease of maintenance. Cooling is accomplished by air or water, with two full capacity cooling systems being supplied.

In addition to the fuel cell output, power to the PEPCO grid is available from two additional sources. The first is from the combustor-expander receiving fuel cell vent gases and the second is the turbine receiving steam from the fuel cell cooling system and heat recovery steam generator

(HRSG). The expander is provided with a motor-generator which for this application is an induction machine. The induction machine is by far the most common piece of rotating electrical equipment in existence today. It is highly reliable and simple in construction. As a motor, the induction machine is used to supply compressed air to the fuel cell cathode during start-up; however, once the expander is operational, the induction machine is used to generate electrical power. Induction generators have been successfully applied in the process industry with ratings as high as 10 MW. The motor-generator requires protective relaying for both modes of operation. This protection must be coordinated with PEPCO. In addition, reactive power requirements for the machine must either be supplied by PEPCO, or capacitors provided as part of the installed system.

The generator for the steam-turbine is a synchronous machine with protective relaying provided for interface with the PEPCO system.

### 3.2.2 Other Site Utilities

All utilities to the GFC are metered for purposes of accounting and performance analysis.

#### a - Water

Fresh water supply is required for the gasifiers, the cooling tower make-up, the sulfur removal system and the Thermal Management System makeup as follows:

	<u>Flow (gpm)</u>
Gasifiers	11
Cooling Tower Make-up	80
Sulfur Removal System	5
Thermal Management Systems	<u>22</u>
Total	118

The water will be supplied from the existing 80 to 85 psig city water main at the Heating and Cooling Plant.

b - Natural Gas

Natural gas (300 scfm per gasifier) is required for startup heater (F-301) in the CO shift section. Additionally, 20 scfm of natural gas are required to support the ammonia flare. Natural gas supplied from the existing 12" main on the west wall of the Heating and Cooling Plant, is used during plant startups.

c - Electric Power

Electric power for the GFC plant auxiliaries (pumps, compressors, fans, lighting, etc.) is supplied by the GFC system. Offsite power is used during plant start-up.

d - Sewage

Effluent from the plant is treated to levels that meet District of Columbia pretreatment requirements before discharge into the existing 21" sanitary sewer line which feeds into the Blue Plains sewage treatment plant.

3.3.1 Anticipated Site Conditions

Estimate of the anticipated subsurface site conditions in areas of proposed construction are based upon 1963 boring data<sup>(4)</sup> compiled for the existing Central Heating-Cooling Plant. Due to the limited coverage of this data in areas of proposed construction, and considerable variability of the subsurface conditions, a more comprehensive subsurface investigation program will be required to supplement this data and provide an adequate basis for final project planning and design.

In general, the site is anticipated to contain:

- a) Residual micaceous sandy and clayey soils, with occasional surficial fill areas, overlying;
- b) A zone of "disintegrated" rock, having variable quality and thickness through the site, overlying;
- c) Relatively sound rock

Although the notes on the boring log drawing classify the rock as granodiorite, experience in the area indicates the rock may be (or behave as) mica schist. Observed variability in the thickness of the weathered or disintegrated rock zone also confirms this rock classification, which is a typical characteristic that is dependent upon the orientation of the rock bedding planes.

A proposed 36' excavation depth here (to El. + 70') is anticipated to encounter only a few feet of surficial soils, with the remainder of the excavation depth encountering approximately equal thickness of "disintegrated" rock and relatively sound rock.

Limited water level measurements performed in completed borings indicate limited and discontinuous zones of water, apparently perched locally on the "disintegrated" rock stratum. Since none of these borings penetrated to the deeper proposed excavation level (Elevation + 70'), it is also possible that additional quantities of water could be encountered in rock fractures and joints located deeper in the formation.

### 3.3.2 Design Considerations

#### 3.3.2.1 Foundation Support

All proposed foundation elements are estimated to be supported on either "disintegrated" rock or relatively sound rock. It is anticipated that these strata will be capable of providing adequate bearing support for the proposed foundations within tolerable settlement limits.

#### 3.3.2.2 Groundwater

It is likely that dewatering will be required during foundation construction to maintain relatively dry working conditions. Proposed subsurface facilities must be designed with the necessary waterproofing, drainage, and/or resistance to bouyant efforts.

### 3.3.3 Construction Considerations

#### 3.3.3.1 Soil Excavation

Excavation through existing fill and soil strata could be accomplished with conventional excavation equipment. The existing boring data indicates that one to one sideslopes could perform acceptably on a temporary basis during construction.

#### 3.3.3.2 Rock Excavation

Available boring data and our experience indicate that ripping would be required to permit excavation of the "disintegrated" rock stratum using conventional excavation equipment. Excavation sideslopes through this

stratum should be approximately one to one. The more durable, sound rock, will require blasting techniques, and appropriate control techniques (limited charges and lift sizes, vibration monitoring, presplitting and line drilling, blasting mats, etc.) to mitigate damage to nearby facilities. Excavation sideslopes in the sound rock could most likely be vertical, although rock bolting and/or shoring may be required locally where rock quality and/or orientation are not suitable for vertical cuts.

#### 3.3.3.3 Existing Foundations

Portions of the proposed excavation may potentially undermine existing foundations (eg. the gasifier unit excavation south of the existing heating plant foundations, or a proposed truck ramp excavation near the existing Gymnasium foundations). In such areas, it may be necessary to underpin these affected foundations to deeper levels, in order to provide for their continued support during construction. Additionally, it may be necessary to shore and brace vertical and/or steep excavation sideslopes (greater than 1:1) through the soil and "disintegrated" rock strata, to maintain stability of these areas during new foundation construction.

#### 3.3.3.4 Backfill and Spoil

The excavated soil and "disintegrated" rock (if broken up into small enough fragments) could potentially be used as compacted backfill around new foundations. However, the fine-grained nature of these materials tends to make them extremely moisture sensitive, and it may therefore be more cost effective to spoil such materials and to use only imported clean (non-moisture sensitive) granular soils for backfill. Considering the large volume of proposed excavation for the project, and the limited need and utility of these materials as fill, appropriate arrangements must be made for the proper disposal of all these excess materials.

#### 3.4 References

- 3-1 ANSI/IEEE C37.95-1973, Guide for Protective Relaying of Utility-Consumer Interconnections
- 3-2 Ebasco Report PRC-HVDC-001, High Voltage Direct Current (HVDC) Reliability Study, dated February 13, 1984.
- 3-3 IEEE 519-1981, Guide for Harmonic Control and Reactive Compensation of Static Power Converters.
- 3-4 Thos. F. Ellerbe/Mariani and Associates Drawing No. S-1, entitled "Log of Soil Borings and General Structural Notes, Heating-Cooling Plant, Phase D", dated 7/3/63.

#### 4.0 ELECTRICAL LOADS

##### 4.1 Present Load

Currently, load at the Georgetown facility is supplied from two PEPCO substations, supplemented by cogeneration and photovoltaic systems. PEPCO supplies these substations via six feeders, each individually metered (demand and kWh). Georgetown is billed using PEPCO's "GT" general service schedule.

The Georgetown load is made up of a base load which includes the hospital complex, security loads and so forth, and noncontinuous loads, such as offices and classrooms. Generally the minimum load is approximately 5400 kW with load increasing from 10AM to noon and decreasing back to the base load between 5 PM and 10PM. Peak load varies with the season, with the summer peak dominant. From data available through June 1984, the high demand for the PEPCO North and South Substations is 6513 kW and 6252 kW respectively versus 7100 kW and 6525 kW available at the substations.

##### 4.2 Future Load

Based on plans for future construction discussed in Section 5.0, the load at Georgetown will continue to increase over current requirements. However future load growth should be minimized by the use of conservation methods and a coordinated energy-management program. According to the referenced information it is expected that the annual consumption of energy as well as demand will increase approximately 50 percent by the year 2000, resulting in a shortage of feeder capacity.

## 5.0 THERMAL LOADS

### 5.1 Present Load

The Main Campus of Georgetown University has a steam load that is divided between three components.

The first component is the requirement of the campus heating system which is fed from an underground steam and return pipe distribution system originating in the HCP at the southwest quadrant of the campus. Pressure reducing stations in each campus building, reduce supply main pressure from a range of 90 to 125 psig to levels suitable for space heating (15 psig), domestic hot water heating, kitchen equipment or hospital equipment as may be applicable.

Data plotted from boiler plant logs dated from 7/83 to 6/84 (see Figure 5-1) shows the campus heating load to have had a maximum monthly average of 63,000 lb/hr in January, 1984. (Loads for other years will vary with the severity of winter and summer weather). Adding plant auxiliaries (steam turbine drives, deaerator, etc), the January average is 74,000 lb/hr with a two hour peak of 111,000 lb/hr

The second component of load is determined by the steam turbines which drive the centrifugal refrigeration compressors of the central chilled water plant. Steam is supplied to these turbines at 275 psig. These units are placed on line in late April and have a maximum monthly average steam requirement that rises to about 78,000 lb/hr during July and August.

The third component of steam load is the requirement of the heating plant auxiliaries which includes small steam turbine drives for pumps, deaerator-feedwater heating and space heating for the power plant.

The combined heating load from all three sources has a monthly average peak of 100,000 lb/hr in July and August which falls to a minimum of 46,000 lb/hr in April.

Maximum two hour peaks between about 115,000 lb/hr and 130,000 lb/hr occurred in each month from May to November.

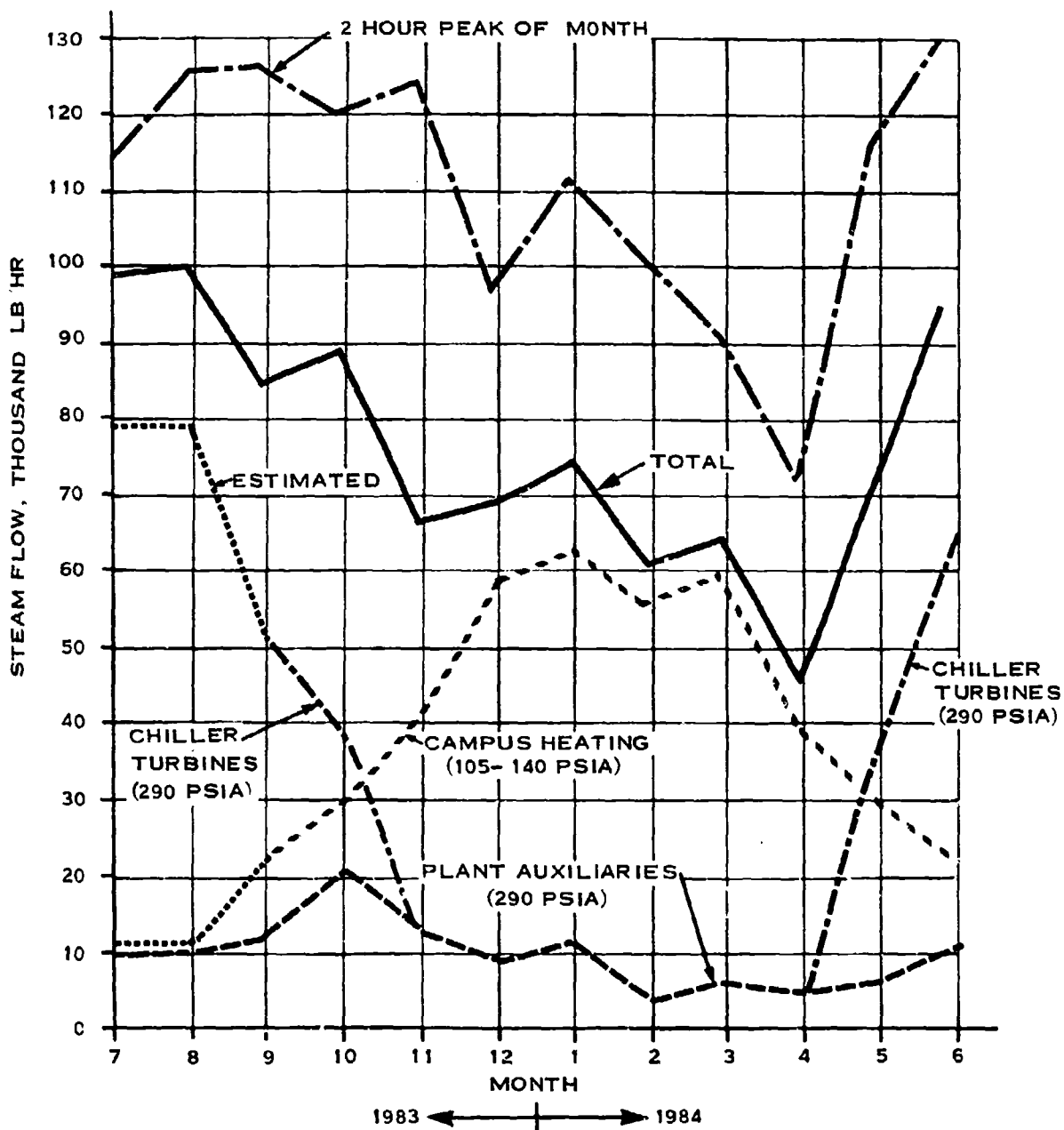


FIGURE 5 - 1 STEAM FLOW, vs MONTH  
WASHINGTON D.C. SITE  
FOR PERIOD 7/1/83 TO 6/30/84

## 5.2 Future Load

Future energy requirements are based on additions shown in Table 5-1. Using this information, a summary of existing and future building area by categories of use is given in Table 5-2.

Existing steam requirements taken from the plant logs and discussed in paragraph 5.1 are tabulated in Table 5-3 along with approximations of future thermal loads.

TABLE 5-1

GEORGETOWN UNIVERSITY BUILDINGS  
GROSS AREAS OF FUTURE ADDITIONS & DEMOLITIONS (1000 ft<sup>2</sup>)

<u>Facility</u>	<u>Educational and Administrative</u>	<u>Medical</u>	<u>Residential</u>	<u>Total</u>
Socioenergy Podium A	116		162	627
Socioenergy Podium B	231		178	640
Socioenergy Podium C	251		158	659
Ancillary Complex	160			600
University Center	106		48	154
Ryan Administration			48	48
Glover Archbold Park Res.			73	73
Incremental Elements			52	52
Additions to Powerplant				
Addition to Lauinger Library	35			35
Commercial Building	7			7
Addition to Basic Science		52		52
Addition to Dental Clinic		50		50
Addition to Dahlgren Med. Lib.		40		40
Interdisciplinary Center		110		110
Clinical Sciences/Health Facility		208		208
Animal Resources Facility		36		36
Addition to Lombardi Center		86		86
Addition to Hospital		68		68
O'Gara (Demolition)	-13			-13
Ryan (Demolition)	<u>-22</u>	<u>—</u>	<u>—</u>	<u>-22</u>
Totals	871	650	269	1,790

TABLE 5-2

SUMMARY OF GROSS AREA (Ft<sup>2</sup>)

	<u>Existing</u>	<u>Future Additions</u>	<u>Future</u>
Educational and Administrative	1,026,000	871,000	1,897,000
Medical	1,238,000	650,000	1,888,000
Residential	<u>1,030,000</u>	<u>269,000</u>	<u>1,299,000</u>
Subtotal	3,294,000	1,790,000	5,084,000

TABLE 5-3

EXISTING<sup>(1)</sup> AND FUTURE THERMAL ENERGY

<u>Existing</u>	<u>Annual Steam Consumption (1000 lb)</u>	<u>Maximum Monthly Average Steam Flow in Year (Lb/hr)</u>	<u>Maximum 2 Hr Peak (Lb/hr)</u>
Campus Heating	322,884	62,000	-
Chiller Turbines	268,780	78,000	-
Plant Auxiliaries	87,213	20,000	-
Total Existing	678,877	100,000 <sup>(2)</sup>	132,000
Future Additions	364,000		
Total Future	1,040,000	153,000 <sup>(3)</sup>	202,000 <sup>(3)</sup>

Notes:

1. Existing thermal energy from plant logs of 7/83 to 6/84
2. Not the sum of maximum monthly averages
3. Assumed to increase in proportion to total annual steam consumption

## 6.0 SYSTEM DESIGN DESCRIPTION

### 6.1 Material Handling

#### 6.1.1 Coal Handling

##### 6.1.1.1 Function and Design Requirements

The function of the coal handling system is to receive, weigh, sample, screen, store, meter and distribute coal to the gasifiers. Daily coal demand for one module, consisting of two (2) gasifiers, is 172 Tons/day with both gasifiers in operation. With the installation of the first module, the coal handling system will incorporate two (2) coal storage bunkers of 686 ton capacity each. This will provide a total of approximately 8.5 days of plant coal storage capacity with both gasifiers in continuous operation.

If a second future module is installed, daily coal demand will be 322 Tons/day. One storage bunkers will be added at that time to bring the total coal storage capacity to 6.4 days at continuous full rated operation of the gasifiers.

##### 6.1.1.2 System Description

The coal handling flow diagram is shown in Figure 6.1-1.

Stoker coal sized at (1-1/4" x 1/4") is delivered to the site in 20 ton trucks.

The trucks discharge into enclosed inground hopper S-001. A typical delivery would be 5 to 8 trucks per day. Water spray nozzles control the release of coal dust during truck unloading.

Belt weighfeeder H-001, reclaims the coal from the hopper, and transfers it to conveyor H-002 which raises the coal and discharges it into conveyor H-003.

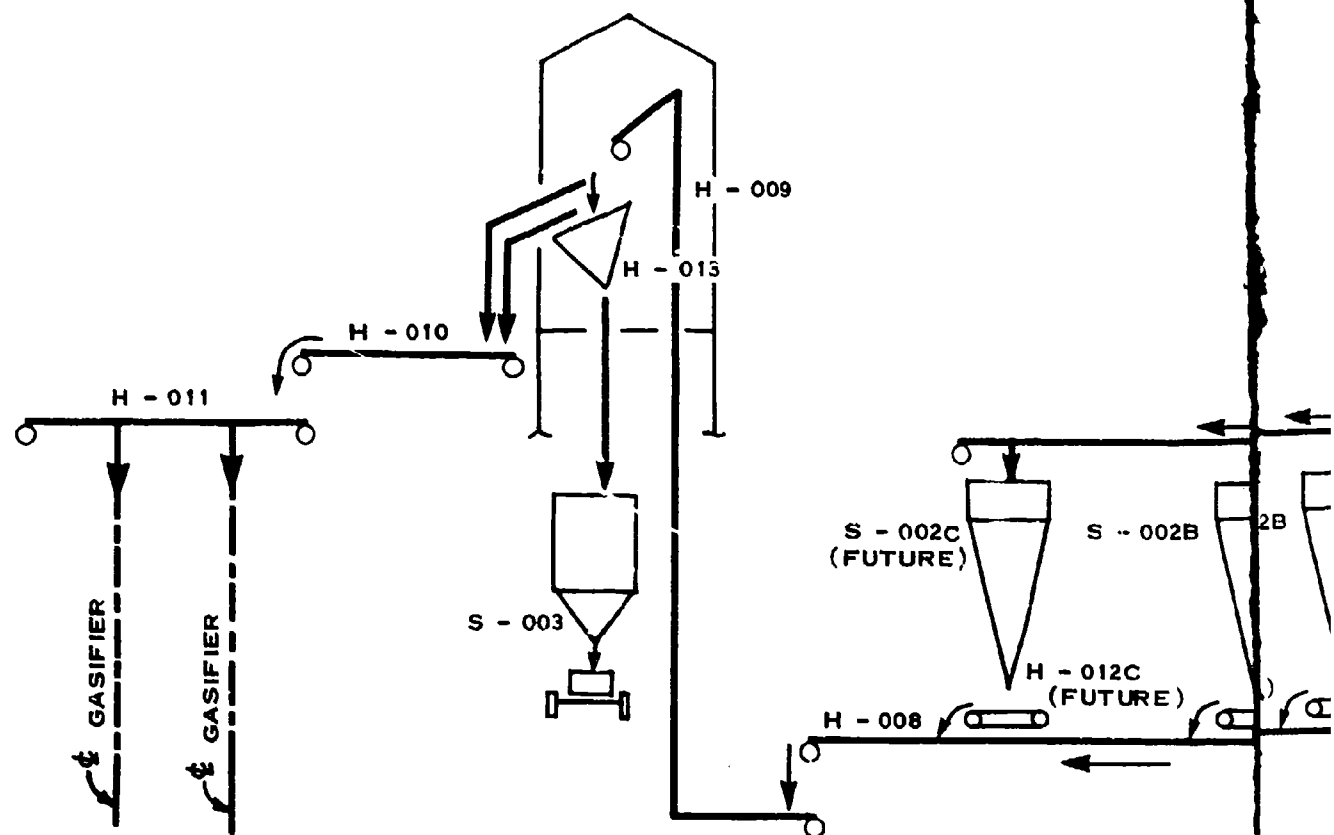
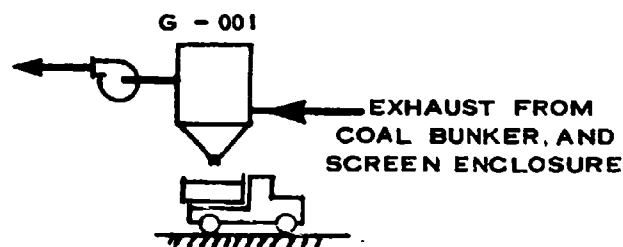
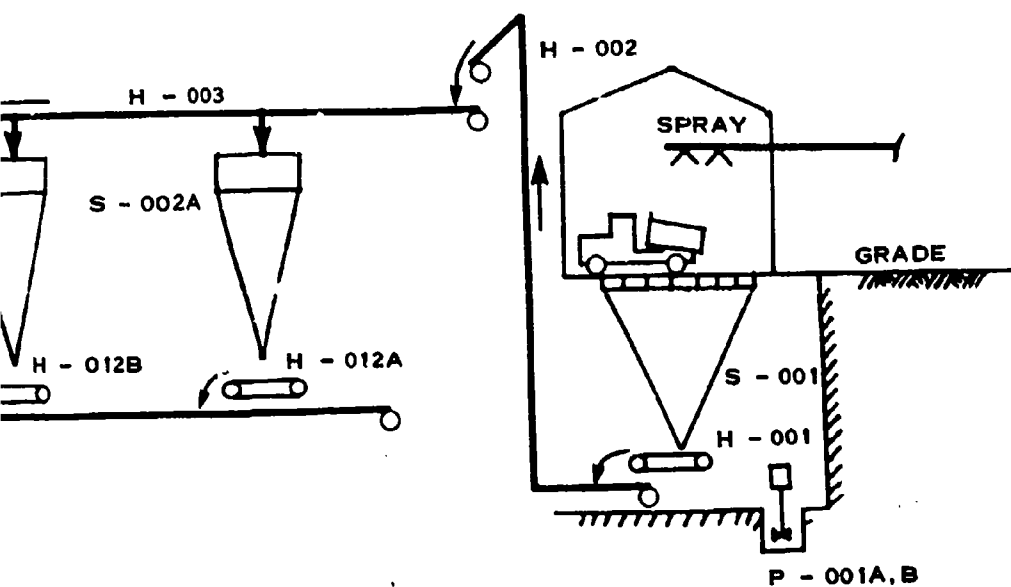


FIGURE 6.2-1



COAL DUST COLLECTION SYSTEM

- |         |                      |      |
|---------|----------------------|------|
| S - 001 | RECEIVING HOPPER     | PPER |
| S - 002 | COAL BUNKER          |      |
| S - 003 | FINES SILO           |      |
| G - 001 | DUST COLLECTOR       | OR   |
| H - 001 | RECEIVING BELT WEIGH | T W  |
| H - 002 | TO                   |      |
| H - 011 | CONVEYORS            |      |
| H - 012 | BUNKER BELT WEIGH    | WEIC |
| H - 013 | SCREEN               |      |
| P - 001 | SUMP PUMP            |      |



EIGHFEEDER

GHFEEDER

DOA / GEORGETOWN UNIVERSITY
COAL GAS / FUEL CELL / COGENERATION
WASHINGTON D.C. SITE PROCESS FLOW DIAGRAM
COAL HANDLING AND STORAGE SECTION
FIGURE 6.1-1
EBASCO SERVICES INCORPORATED

Conveyor H-003 discharges into any of the bunkers S-002A, S-002B (or future bunker S-002C).

Belt weighfeeders H-012A, and H-012B reclaim coal from bunkers S-002A and S-002B and discharge into conveyor H-008 which discharges into elevating conveyor H-009.

By means of a flop gate, conveyor H-009 diverts the coal to either Screen H-013 or to conveyor H-010. Coal over 1/4" size is discharged from the screen deck into conveyor H-010 (a bypass chute permits collection of coal samples). Fines less than 1/4" passing through the screen, flow from the screen fines hopper into fines collection silo S-003 which discharges intermittently into an enclosed truck.

Conveyor H-010 discharges into conveyor H-011 which in turn feeds coal to either of the two gasifiers.

In the future, if an additional gasification module is added, new conveyors and feeders will be installed in conjunction with the new bunker. A new conveyor will be added in series with conveyor H-011 to supply the new gasifier.

To collect the coal dust generated during the coal handling operations and to disperse any methane generated in the coal bunkers, a bag type dust collector is installed in the coal handling and storage area.

The dust collector is equipped with two 100% capacity exhaust fans.

To remove any water accumulated in the reclaim hopper pit, a sump with two 100% capacity sump pumps is installed.

Coal dust accumulated on the floor of the coal bunker and gasifier areas is hosed with water, the water/coal dust mixture draining to the reclaim hopper sump.

### 6.1.1.3 System Performance

Except for the belt weighfeeders the rest of the conveying equipment consists of "en masse" conveyors.

This type of conveyor moves the coal as a solid column at the same speed as the conveying element, resulting in minimum fines generation due to the lack of relative movement between coal lumps and between the coal and conveying element.

Chain speeds of "en-masse" conveyors are relatively slow. The conveyors consist of a continuous chain, an enclosed casing, a gear reducer, coupling, motor and sprockets. Preventive maintenance is simple and replacement parts can be stored at the plant.

With an 8.5 day coal storage capacity, there is sufficient time to repair the coal unloading system without interrupting plant operation.

### 6.1.2 Ash Handling System

#### 6.1.2.1 Functions and Design Requirements

The function of the ash handling system is to remove ash collected in the gasifier storage hoppers. Additionally, the design considers the environmental impacts associated with the handling of powder type materials which can be a source of dust emissions.

#### 6.1.2.2 System Description

Ash produced through the gasification of coal is collected and stored in a conical hopper located below the revolving grate of the gasifier.

Dust or fly ash entrained in the gas leaving the gasifier is separated in a cyclone separator and collects in its conical storage hopper. Each storage hopper is sized for a minimum of 24 hours storage. The capacity of the ash hopper, based on a material flow rate of 1,153 lbs/hr is 13.8

tons. The cyclone hopper can collect 2.6 tons of dust in a 24 hour period, based on an hourly flow of 215 lbs/hr.

Each hopper is furnished with a sliding gate operated by a manual rack and pinion gear. Ash and dust is unloaded from their respective hoppers into a covered dump truck for offsite disposal. Prior to unloading the ash hopper, an operator floods the hopper with water and then dewateres it to a moisture content of approximately 30 percent by weight before opening the gate. The moist material does not cause any fugitive dust emissions.

Dust collected in the cyclone hopper is stored in a wet state and unloaded with the ash into the covered dump truck.

#### 6.1.2.3 System Performance

The ash removal and handling system utilizing truck disposal provides high reliability and availability. It is assumed that the trucking operation will be performed on a contract basis and that certain guarantees in the contract will be made to assure daily removal of ash and dust.

#### 6.1.2.4 Maintenance

Operation of this system is local and manual. Manual loading of materials into containers, vehicles, etc., is the most widely used method and by far the simplest. Control of the ash hopper flood cycle is also local and operator initiated. With a proper preventive maintenance program implemented, critical components such as isolating gates should not fail during operation.

#### 6.1.2.5 Technical Risks

Risk associated with ash and dust removal is limited to the availability of trucks to receive the ash and dust and ability of the isolating gate to operate. During inclement weather or other events which prevent trucks from removing ash and dust, dumpsters provide temporary onsite storage.

A situation where potential loss of availability may occur is when an isolating slide gate fails to open or close or is worn to its limit thereby not effectively isolating material flow. The manually operated rack and pinion gear should ensure closure and opening of the gate and a proper maintenance program should detect blade wear prior to malfunction.

## 6.2 Coal Gasification

### 6.2.1 Functions and Design Requirements

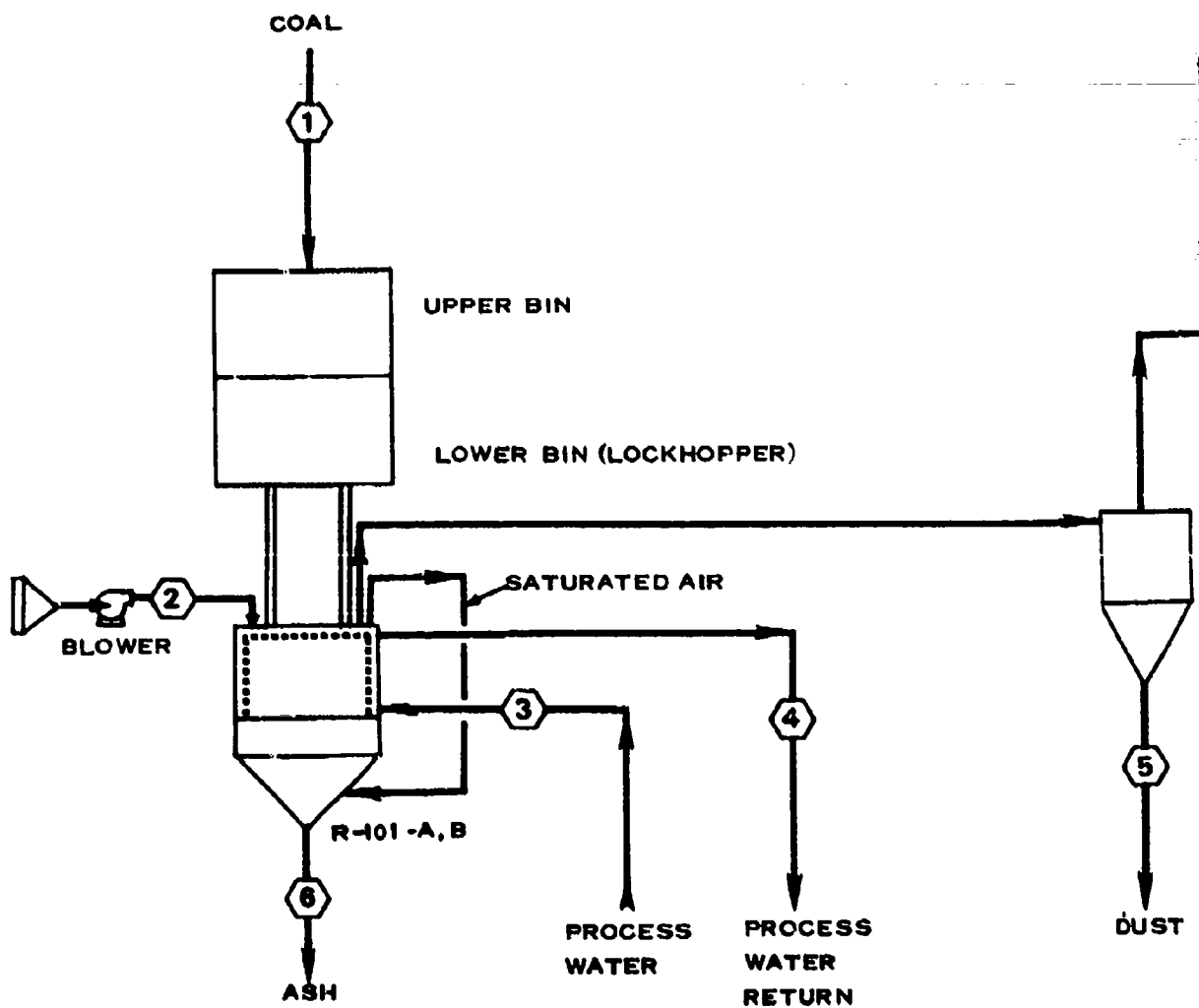
The function of the Coal Gasification Section is to convert coal energy to gaseous form suitable for processing prior to its use in a fuel cell.

The controlling design criteria for the Coal Gasification Section is the concentration of carbon, hydrogen and volatile matter in the design coal. The feedstock used for this study is an eastern Kentucky bituminous coal with composition and characteristics shown in Table 6.2-1.

Design capacity of the gasifier is based on the United Technologies fuel cell requirement of 775 mols of hydrogen per hour.

A fixed bed air blown atmospheric single stage Wellman-Galusha gasifier was selected as the basis for this study. This selection was based primarily on the decision to use fully commercialized technology. The Wellman-Galusha gasifier having been in use for 50 years has a large data base of technical and economic information. Another criteria for gasification technology selection was the size of the gasifier. This fuel cell system requires a relatively small gasification plant eliminating larger gasifiers from use in this application.

FIGURE  
6.1-1



RAW GAS  
TO T-201

7

FIGURE  
6.3-1

H-102 -A, B

R-101- A, B GASIFIER

H-102- A, B C LONE

5

DUST

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WASHINGTON D.C. SITE

PROCESS FLOW DIAGRAM

COAL GASIFICATION SECTION

FIGURE 6.2-1

EBASCO SERVICES INCORPORATED

In addition, the Wellman-Galusha unit is able to process coal with a Free Swelling Index up to 5 covering a wider range of coals than comparable technologies.

The raw gas composition produced by the Wellman-Galusha gasifier from the design coal is shown in Table 6.2-2.

The total consumption of coal is 172 T/Day producing 2,767 million Btu/day of coal gas at a gasification efficiency of 62%. If the heating value of tars and oils is included, the gasification efficiency is 83%.

The material balance for the gasifier is given in Table 6.2-3.

TABLE 6.2-1

COAL ANALYSIS

## o COAL (EASTERN KENTUCKY BITUMINOUS)

## Proximate Analysis (as received, %)

Moisture	5.78
Ash	7.74
Volatiles	38.42
Fixed Carbon	48.06

## Ultimate Analysis (dry basis %)

Carbon	70.21
Hydrogen	5.05
Nitrogen	1.44
Sulfur	1.70
Chlorine	0.04
Ash	8.21
Oxygen (by diff)	13.35

High heating value (as rec/d Btu/Lb)	13,000
Ash Fusion, Initial Def (°F)	2,266 (Red)
Free Swelling Index	4.0

TABLE 6.2-2

RAW GAS COMPOSITION

	<u>Mol %</u>	(Dry Basis)
H <sub>2</sub>	17.43	
CO <sub>2</sub>	6.92	
C <sub>2</sub> H <sub>4</sub>	0.12	
C <sub>2</sub> H <sub>6</sub>	0.18	
N <sub>2</sub>	49.28	
CH <sub>4</sub>	1.69	
CO	23.95	
H <sub>2</sub> S	0.29	
COS	0.04	
NH <sub>3</sub>	0.08	
HCN	<u>0.02</u>	
	100.00	
Water Yield Lb/Lb Coal		0.29
Tar Yield Lb/Lb Coal		0.16
Gas Temperature °F		770

Notes:

1. For eastern Kentucky bituminous coal

TABLE 6.2-3

GASIFIER MATERIAL BALANCE

<u>INPUT</u>	<u>LB/HR</u>
Coal Feed (As received)	14,349
Air, Dry	34,475
Steam	<u>5,948</u>
Total	54,772

<u>OUTPUT</u>	
Dry Gas	47,136
Tars and Oils	2,163
Water Vapor	3,920
Ash Purge	1,153
Cyclone Dust	215
Unaccounted	<u>185</u>
Total	54,772

### 6.2.2 System Description

The process flow diagram for the gasification system is shown on Figure 6.2-1 and the mass balance in Table 6.2-4.

At the top of each Wellman-Galusha gasifier (R-101 A & B) is an open coal bunker or "upper bin". Following that in the downward direction is a gas tight lower coal bin or "lockhopper" in the gasifier reactor vessel and finally, the ash cone at the bottom<sup>(2)(3)</sup>.

The upper bin is filled by the bucket elevator and discharges coal by gravity into the lower bin. The lower bin has interlocking gas tight valves top and bottom configured such that the bottom valves close before the top valves open, and vice versa. The upper valves open, allowing coal to flow by gravity into the lockhopper. When the lockhopper is filled, usually in a matter of a few minutes, the valves are cycled, closing the upper valves and opening those at the bottom.

The lower fuel valves are kept open, except for refueling, to assure a continuous supply of fuel into the gasifier reactor vessel.

The gasifier R-101 is a double wall cylindrical vessel, with an inner shell of one inch thick steel. A water jacket surrounds the side of the inner shell and extends over the top. About four inches above the top of the inner wall there is an overflow pipe which prevents the water from completely filling the space between the inner and outer shell at the top of the vessel. Cooling water is introduced into the water jacket at the top of the vessel, and flows out through the overflow.

Air to sustain combustion is supplied by blower. After absorbing moisture as it passes over the open water surface in the top of the water jacket, the air enters the gasifier vessel from below the grate plates, flowing upward through the ash bed. The moisture carried by the air flow moderates the temperature of the fire bed preventing the formation of clinkers. The amount of water vapor absorbed depends upon jacket water temperature which is controlled by varying cooling water flow. The water vapor thus introduced reacts chemically with the hot carbon generating gaseous products.

Coal flowing down through the feed pipes enters the top of the gasifier and is contacted by the upward flow of hot gas produced in the gasifier reactor. The heat from the countercurrent flow of hot gas first evaporates moisture, then drives off volatiles from the incoming coal. The moisture and volatile matter become part of the outward bound gas stream. The dry, devolatized coal char continues its slow downward flow through the gasifier at a rate determined by the air flow into the unit which, in turn, sets the gasification rate. The coal char passes through two stages. The first stage consists of a reducing zone, where carbon dioxide produced from char which is burning below is reduced to carbon monoxide. Water vapor added to the incoming air is also reduced in this zone by the hot carbon in the char, producing hydrogen and additional carbon monoxide. The heat supporting this endothermic reaction is produced by the first zone directly below, wherein the carbon in the char is burned to form carbon dioxide.

The gasifier is provided with an agitator which retards channeling and maintains a uniform fuel bed.

The burning coal in the fire zone rests upon a bed of ash produced by the combustion of the coal char, and this bed of ash in turn is supported by a slowly revolving set of eccentric grates.

Ash removed from the gasifier vessel by the revolving grate drops into an ash cone at the bottom of the vessel. From there it is flushed out periodically with water into a truck. Flushing the ash is of a few minutes duration and does not interfere with the normal operation of the gasifier.

The depth of the ash and fire zones is monitored by the insertion of rods through pokeholes located on top of the gasifier. Steam sealed pokeholes will be used to prevent gas leaks during the poking operations.

The hot gas produced in the gasifier contains some particulates, some moisture, and volatile matter, principally aerosol tar and oil. The hot gas flows through tangential entry dust cyclone H-402, which separates particulates from the gas stream. The hot gas then flows directly to gas

cleaning equipment. Composition of the gas at this point is shown in Table 6.2-2(3).

The cyclone is designed to be used as a water sealed gas shut-off valve and provides a positive leak-proof shut-off without the use of a mechanical valve. The separated particulates are stored in the cyclone cone section and flushed into a truck at the same time the wet ash is unloaded from the gasifier, in order to minimize dust emissions.

### 6.2.3 System Performance

The Wellman-Galusha gasifier is rated at a capacity of 7000 Lbs/hr bituminous coal when provided with an agitator. The gasifier has converted into gas as much as 99 pounds of coal per square foot of grate per hour. This represents 7770 lbs/hr of coal gasified, or 111% of rated capacity. Also, in commercial operation, it has processed as little as 7.5 pounds of coal per square foot of grate per hour or about 8.5% of capacity. This makes it possible to operate the gasifier without venting the excess gas to atmosphere when the demand is small. The gasifier can be operated at part load without a loss in efficiency<sup>(4)</sup>. The gasifier has no refractory lining in the gas making chamber, eliminating liner maintenance, a primary cause of shutdown for other types of gasifiers. A two week scheduled annual shutdown for maintenance with an estimated three days of unscheduled shutdown brings the estimated availability of the gasifier to 95%. Gasification will proceed at a total coal flow rate of 13,411 lbs/hr to two modules each operating at 100% capacity based on the material balance in Table 6.2-3.

### 6.2.4 Maintenance

The maintenance work anticipated for the section is minimal and requires the daily flushing of the gasifier jacket. During the scheduled two week annual shutdown, repair or replacement is made as required of the moving grates, bearings, or other moving parts. Lockhopper disk valves are cleaned and poke hole seal valves are checked.

TABLE 6.2-4

## MASS BALANCE - COAL GASIFICATION SECTION

Stream No. Stream Name	1 Coal	2 Air	3 Gasifier Jacket Water Inlet	4 Gasifier Jacket Water Outlet	5 Cyclone Dust	6 Ash Purge	7 Producer Gas
	Lb Mol/hr	Lb Mol/hr	Lb Mol/hr	Lb Mol/hr	Lb Mol/hr	Lb Mol/hr	Lb Mol/hr
Components							
H <sub>2</sub>	2.016						336.50
CO <sub>2</sub>	44.610						133.60
C <sub>2</sub> H <sub>4</sub>	28.032						2.40
C <sub>2</sub> H <sub>6</sub>	30.043						3.50
N <sub>2</sub>	28.016						951.50
CH <sub>4</sub>	16.032						32.70
CO	28.011	935.34					462.50
H <sub>2</sub> S	34.080						5.55
COS	60.070						.76
NH <sub>3</sub>	17.030						1.51
HCN	27.030	259.22					0.32
O <sub>2</sub>	32.000		2,305.6	2,013.0			215.90
Ar	39.948	37.47					
H <sub>2</sub> O (water)	18.016	1,232.03	2,305.6	2,013.0			2,146.74
H <sub>2</sub> O (Steam)	18.016	35,150	41,538	36,267			
Total Flow							
Total Flow					215	1,153	
Solids							
Tar	14,349						2,163
Pressure							
Temperature		14.7	90	145			15
		90					770

The mechanical components of the gasifier can be considered as potential technical risks. These components include the coal feed system, the agitator and the moving grates. However, potential problems in these areas have been virtually eliminated by design improvements made in the course of many commercial applications<sup>(4)</sup>.

The coal feeding system has no moving parts, thus eliminating the problems common to machines where mechanical devices are used on highly abrasive fuels. The design features now include replaceable bushings and oversized ball thrust bearings with oil and grease dams for the revolving grate assembly. The agitator arm and its vertical drive shaft are made of heavy water-cooled steel tubing with the wear parts protected by heat and wear resistant castings. Because of such design features the technical risk for the mechanical components is minimal.

Consideration must be given to the possibility that the feed coal contains more fines than can be tolerated by the gasifier. The Wellman-Galusha gasifier can accept up to 15% of its coal feed in sizes below 1/4 inch. If the percentage of fines exceeds 15%, the pressure differential across the coal bed can be excessive, and there can occur a high carryover of ungasified coal into the cyclone. This condition can have a significant impact on the efficiency of operation. To eliminate this risk, an additional set of coal sieves located at the gasifier coal bins, is included in the design of the plant.

6.2.6 References

- 6.2-1 Synthetic Fuels Associates, Inc, "Coal Gasification: A Guide to Status, Applications and Economics", EPRI AP-3109, June 1983.
- 6.2-2 Wellman Gasification Technology - Technical Manual
- 6.2-3 Personal Communication with Dravo Engineers, Inc.
- 6.2-4 Wellman-Galusha Gas Producers, Dravo
- 6.2-5 Gas Engineers Handbook, the Industrial Press, 1965

## 6.3 GAS PROCESSING

### 6.3.1 Functions And Design Requirements

The function of the Gas Processing System is to cool, clean and compress the gasifier effluent and then convert it to a hydrogen rich, sulfur free stream suitable as feed for the fuel cell. This section also includes a Process Condensate Treatment Section, where the toxic and organic matter are removed from the process waste water to satisfy environmental requirements before discharge.

The design criteria for the Gas Processing System is the anode feed gas specification given in Table 6.4-1. The design criteria for the Process Condensate Treatment Section is the waste water effluent specification, given in Table 6.3-1.

### 6.3.2 System Description

The Gas Processing System includes the following sections:

- Gas Cooling, Cleaning and Compression
- CO Shift
- Sulfur Removal and Recovery
- Process Condensate Treatment

The gasifier effluent is at 770°F and contains vapors of tars, oils, phenol, ammonia and particulates that must be removed before further processing. By cooling the gas the hydrocarbons condense and are easily removed by physical separation processes<sup>(2)</sup>. The series of processes used to clean and cool the gas, the direct cooling by spraying with water followed by removal of condensed hydrocarbons in an electrostatic precipitator, have been traditionally used and improved over the years in the coke oven industry and fixed bed gasifiers product gas cleaning<sup>(1)</sup>.

TABLE 6.3-1

TREATED PROCESS EFFLUENT CHARACTERISTICS<sup>(1)</sup>

	<u>mg/l</u>
COD(2)	150
Phenol	0.3
HCN	0
NH <sub>3</sub>	1
H <sub>2</sub> S	0
Suspended Solids	20

Notes:

1. Personal communication with Zimpro Environmental Control Systems.
2. COD = Chemical Oxygen Demand.

In the CO Shift Section the hydrogen ( $H_2$ ) concentration in the gas is adjusted to the requirements of the fuel cell by conversion of the carbon monoxide (CO) to  $H_2$  by reaction with steam over a catalyst.

The presence of sulfur compounds in the fuel gas led to the selection of a highly active sulfur tolerant chromium-molybdenum (COMO) shift catalyst. The catalyst is activated by small amounts of sulfur in the gas and is active within a wide range of temperatures. Part of the carbonyl sulfide (COS) present in the gas is hydrolyzed in the process and converted to  $H_2S$  and  $CO_2$ .

Another option was to remove the sulfur compounds first and use a conventional iron-chromium catalyst for the CO Shift reaction.

The choice of a sulfided shift process was determined by the selection of the Sulfur Removal process, which does not remove the carbonyl sulfide (COS) present in the gas. This sulfur compound, even in trace amounts, would poison a conventional CO Shift catalyst.

A two stage shift reaction with the second bed operating at lower temperatures was selected for this application. Both reactions, the CO shift and the COS hydrolysis take place simultaneously, but the bulk of COS hydrolysis occurs in the second bed. This design will achieve the desired CO conversion and will reduce the COS concentration in the gas to about 30 ppm by volume.

The specifications for the anode fuel require a maximum sulfur content of 4 ppm (Vol). Virtually, total sulfur removal from the gas must be achieved.

There are a number of sulfur removal processes commercially available, for treating the  $H_2S$  bearing gases<sup>(3)(4)</sup>. These processes include chemical and physical absorption systems, which remove the sulfur compounds from the gas down to the desired level.

The physical absorption processes require low temperature operation and high  $H_2S$  partial pressure. The chemical absorption processes are not selective and remove  $CO_2$  with the  $H_2S$ . The regeneration of the solvent requires large steam consumption to strip the absorbed gases, especially with the addition of  $CO_2$ .

The selection of a sulfur removal process was based on gas composition considerations. The gas produced by an atmospheric gasification such as the Wellman-Galusha gasifier has a very low  $H_2S$  partial pressure due to the dilution of the gas with the nitrogen from the air used in the gasification process and the relatively low gas pressure, even after compression to 160 psia. This low  $H_2S$  partial pressure eliminates the physical absorption systems as possible process choices. The chemical absorption processes are a costly alternative for the sulfur recovery process due to the high  $CO_2$  concentration in the gas (24% Vol).

Therefore, a Stretford liquid oxidation process was chosen for this plant. In this process, the  $H_2S$  in the gas is absorbed in a solution where it is chemically oxidized to sulfur and water. The sulfur is separated from the solution, which is regenerated by air-sparging and recycled.

Because the Stretford process cannot remove COS, a hydrolysis step is required to convert the remaining COS to  $H_2S$ . A highly active catalyst, Haldor Topsøe CKA activated alumina was used to reduce the COS to levels accepted by the fuel cell operation. This catalyst can promote hydrolysis effectively at a relatively low temperature.

The traces of  $H_2S$  in the gas are removed in a polishing step over Zn oxide beds.

The condensate from the gas cooling section contains phenols, ammonia, cyanides and hydrogen sulfide. To prevent the buildup of these products in the circulating waste water, a purge stream is removed from the process condensate and discharged as waste water effluent. Before being discharged the waste water is treated for the removal of the pollutants. Two processes were considered to be used for this purpose; the Wet Air Oxidation Process (WAO) and the Powdered Activated Carbon Treatment

(PACT)<sup>(8)</sup>. The PACT process uses powdered activated carbon in conjunction with conventional biological treatment to remove contaminants and was selected to be used in this plant because it has substantially lower investment costs than the Wet Air Oxidation Process for this size unit.

### Process Description

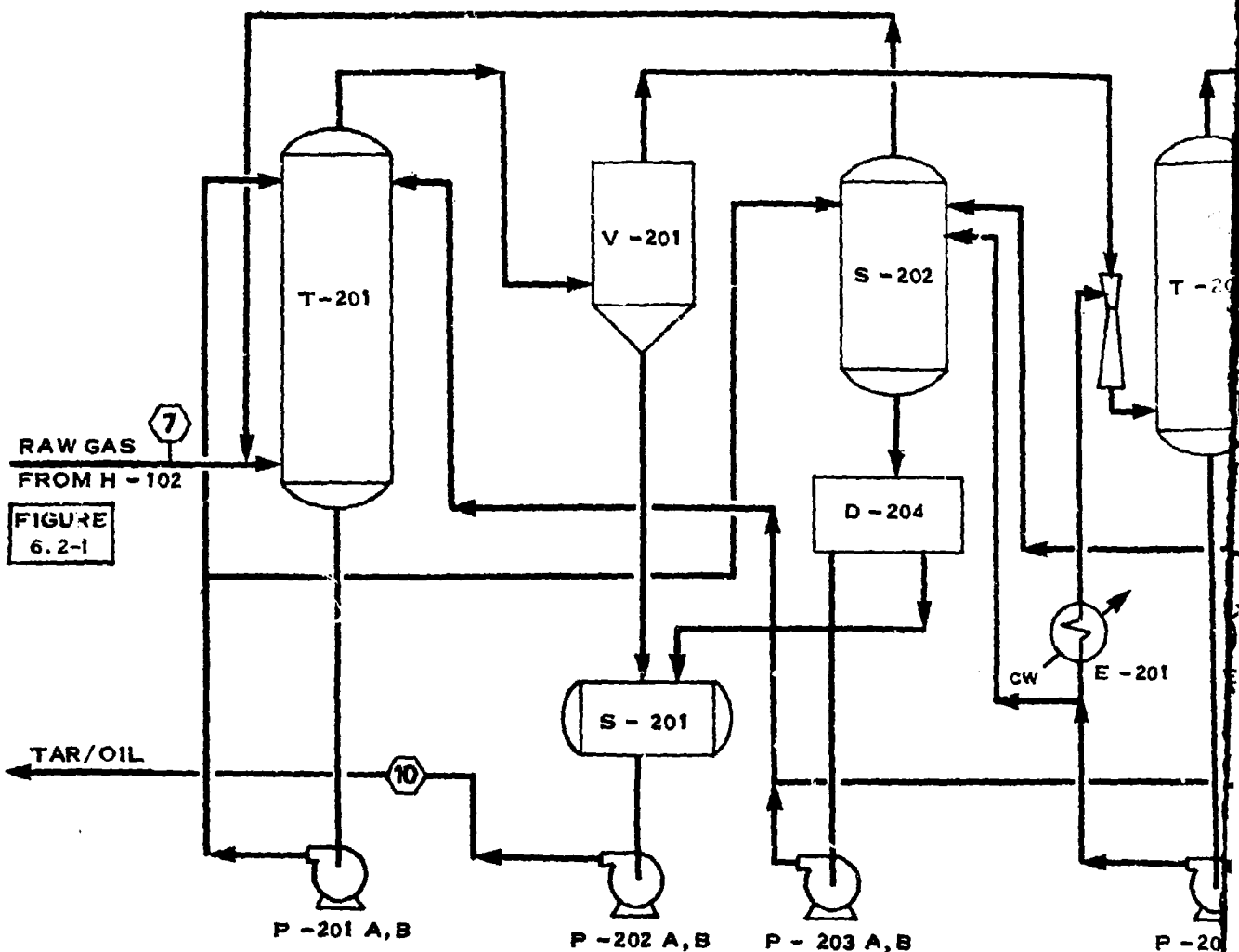
#### Gas Cooling, Cleaning and Compression

The configuration of the Gas Cooling, Cleaning and Compression Section is given in Figure 6.3-1 and the Mass Balance in Table 6.3-2.

The hot gases leaving the gasification section contain some entrained particulates as well as vaporized tars and oils. The gases are first adiabatically cooled to saturation by recirculating liquor through the saturator, T-201. This direct contact water quench condenses the vaporized tars and oils, mixes the oily droplets with the scrubber water and removes additional particulates. The larger drops of oil are removed by the liquor and the smaller sized particles remain entrained in the gas. Remaining mist and particulate matter are removed in the dispersed phase electrostatic precipitator, V-201. In the electrostatic precipitator the negatively charged particles dispersed in the gas are attracted to the positively charged collecting elements and discharged from the system.

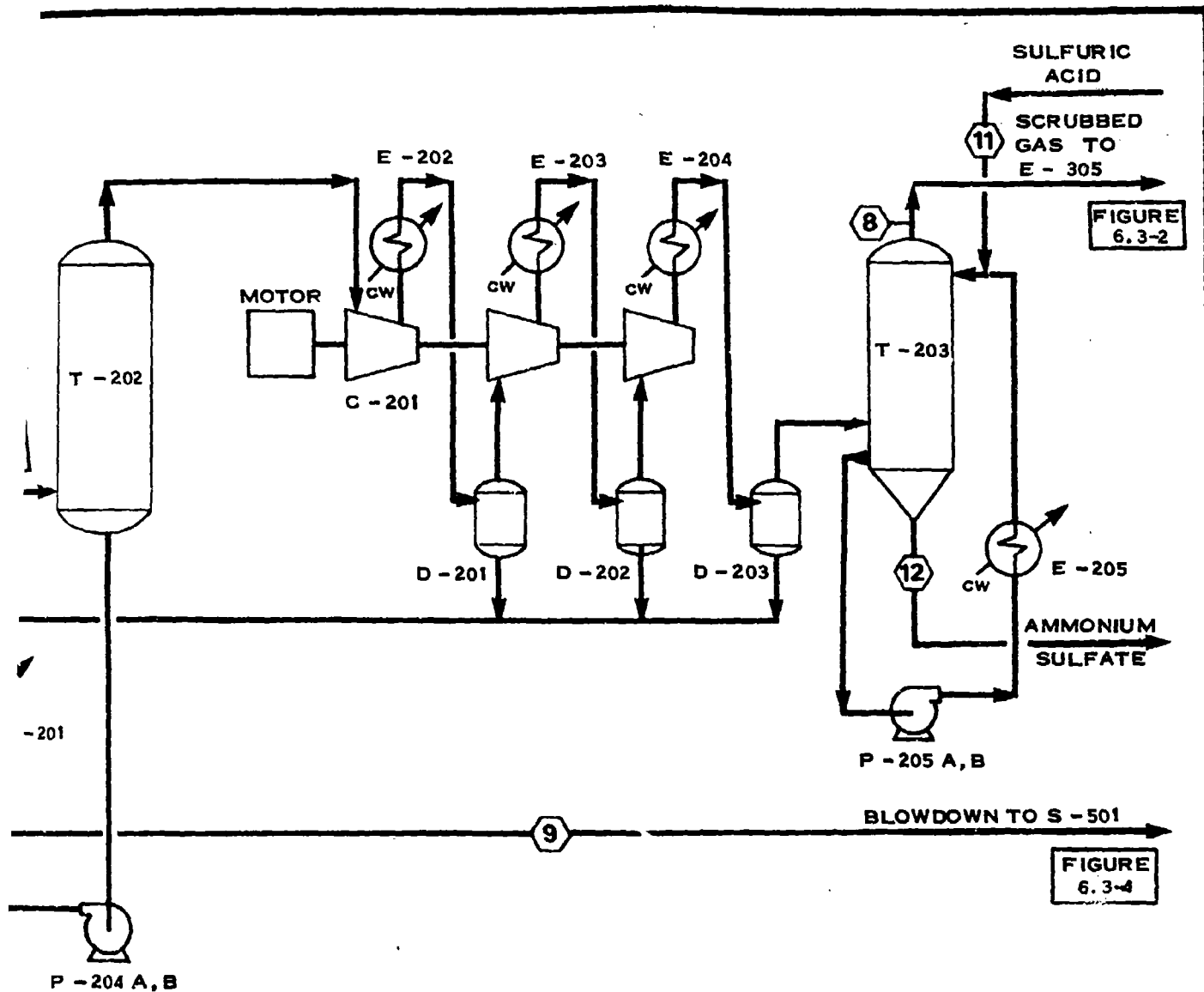
Final cooling of the gas is effected in primary cooler, T-202 by contacting the gas in a venturi jet with externally cooled circulating liquor. The cooling causes further condensation of hydrocarbons and water vapor.

Purge streams from the circulating saturation liquor and primary cooler combined with that from gas compression intercooler KO drums, are delivered to the liquid phase electrostatic precipitator, D-204 via the liquor collection tank, S-202 for separation of tars and oils. The gas phase is recycled to the saturator. The tars and oils separated by gravity from the water in D-204 are combined with those removed in the



T - 201 SATURATOR  
V - 201 DISPERSED PHASE PRECIPITATOR  
D - 204 TAR SEPARATOR  
S - 202 LIQUOR COLLECTION TANK  
T - 202 PRIMARY COOLER  
C - 201 GAS COMPRESSOR  
E - 202 1ST STAGE INTERCOOLER  
E - 203 2ND STAGE INTERCOOLER  
E - 204 3RD STAGE INTERCOOLER  
T - 203 AMMONIUM SULFATE SATURATOR

P - 201 A, B SATURATOR PUMP  
S - 201 TAR COLLECTION TANK  
P - 202 A, B TAR PUMP  
P - 203 A, B LIQUOR PUMP  
P - 204 A, B PRIMARY COOLER PUMP  
D - 201 1ST STAGE K.O. DRUM  
D - 202 2ND STAGE K.O. DRUM  
D - 203 3RD STAGE K.O. DRUM  
P - 203 A, B ACID CIRCULATION PUMP  
E - 205 AMMONIUM SULFATE SATURATOR COOLER



DOA / GEORGETOWN UNIVERSITY  
 COAL GAS / FUEL CELL / COGENERATION  
 WASHINGTON D.C. SITE  
 PROCESS FLOW DIAGRAM  
 GAS COOLING, CLEANING AND  
 COMPRESSION SECTION  
 FIGURE 6.3-1  
 EBASCO SERVICES INCORPORATED

TABLE 6.3-2

## MASS BALANCE - GAS COOLING, CLEANING AND COMPRESSION SECTION

Stream No. Stream Name	7	8	9	10	11	12
	Producer Gas	Compressed Gas	Process Condensate Blowdown	Tars/Oils	Sulfuric Acid	Ammonium Sulfate
Components	Lb Mol/hr	Lb Mol/hr	Lb Mol/hr	Lb Mol/hr	Lb Mol/hr	Lb Mol/hr
H <sub>2</sub>	336.50	336.50				
CCl <sub>2</sub>	133.60	131.80	1.80			
C <sub>2</sub> H <sub>4</sub>	2.40	2.40				
C <sub>2</sub> H <sub>6</sub>	3.50	3.50				
N <sub>2</sub>	951.50	951.50				
CH <sub>4</sub>	32.70	32.70				
CO	462.50	462.50				
H <sub>2</sub> S	5.55	5.55				
COS	.76	0.76				
NH <sub>3</sub>	1.51	-	1.12			
HCN	0.32	0.32				
O <sub>2</sub>						
Ar						
H <sub>2</sub> O (Water)						
H <sub>2</sub> O (Steam)	215.90	11.0	204.90			
Total Flow	2,146.74	1,938.53	207.82			
Total Flow						
Tars/Oils	2,163			2,163		
Sulfuric Acid					19	
Ammonium Sulphate						25
Pressure	15	167	17			
Temperature	770	100	123			

electrostatic precipitator V-201 and maintained in a liquid state in the steam heated tar collection tank, S-201. From here, the tar/oil is pumped off site. Part of the water overflow from the tar separator D-204 is circulated to the saturator to maintain water balance. The remaining overflow serves as system blowdown and is sent to the Process Condensate Treatment Section.

Multistage centrifugal compression (C-201) with interstage cooling is provided to increase the gas pressure. Condensate, consisting of hydrocarbons and water, produced in the water cooled interstage coolers is returned to the liquor collection tank in the cooling/cleaning area.

The compressed and cleaned gas leaving the section is washed with sulfuric acid in Ammonium Sulfate Saturator T-203 to remove ammonia not scrubbed out in the cooling and cleaning of the gas. The heat of this neutralization is removed by circulating the wash liquor through an external heat exchanger E-205. The ammonia-free gas exits to the CO Shift section.

#### CO Shift

The CO Shift reaction is carried out in two stages. It is a highly exothermic reaction and the heat of reaction is used to preheat the feed to the first stage to raise steam and to preheat the clean gas before the final polishing.

The configuration of the CO Shift Section is shown in Figure 6.3-2 and the Mass Balance in Table 6.3-2. The temperature of scrubbed gas leaving the gas compression section is raised in preheaters E-305 and E-302 followed by direct injection of medium pressure steam. Upon further preheating with 1st shift effluent in heat exchanger E-301, the wet gas is introduced into the first stage reactor, R-301. After the reaction, the first stage effluent is cooled by heat exchange with the feed. Further heat recovery takes place by generation of medium pressure steam, and the cooled first stage effluent is introduced into the second stage of water gas shift reactor, R-302.

FIGURE  
6.3-1

SCRUBBED GAS FROM T- 203

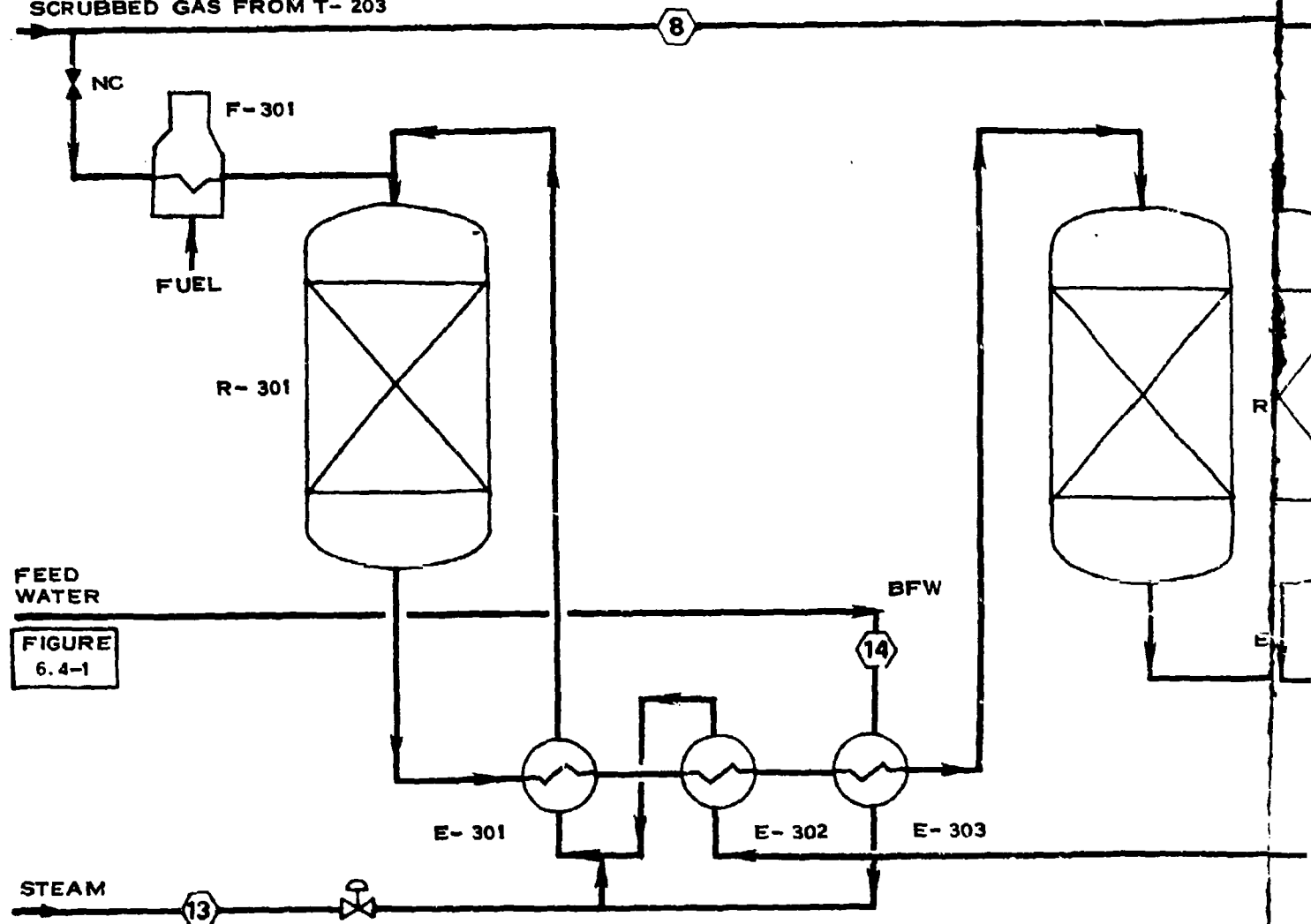
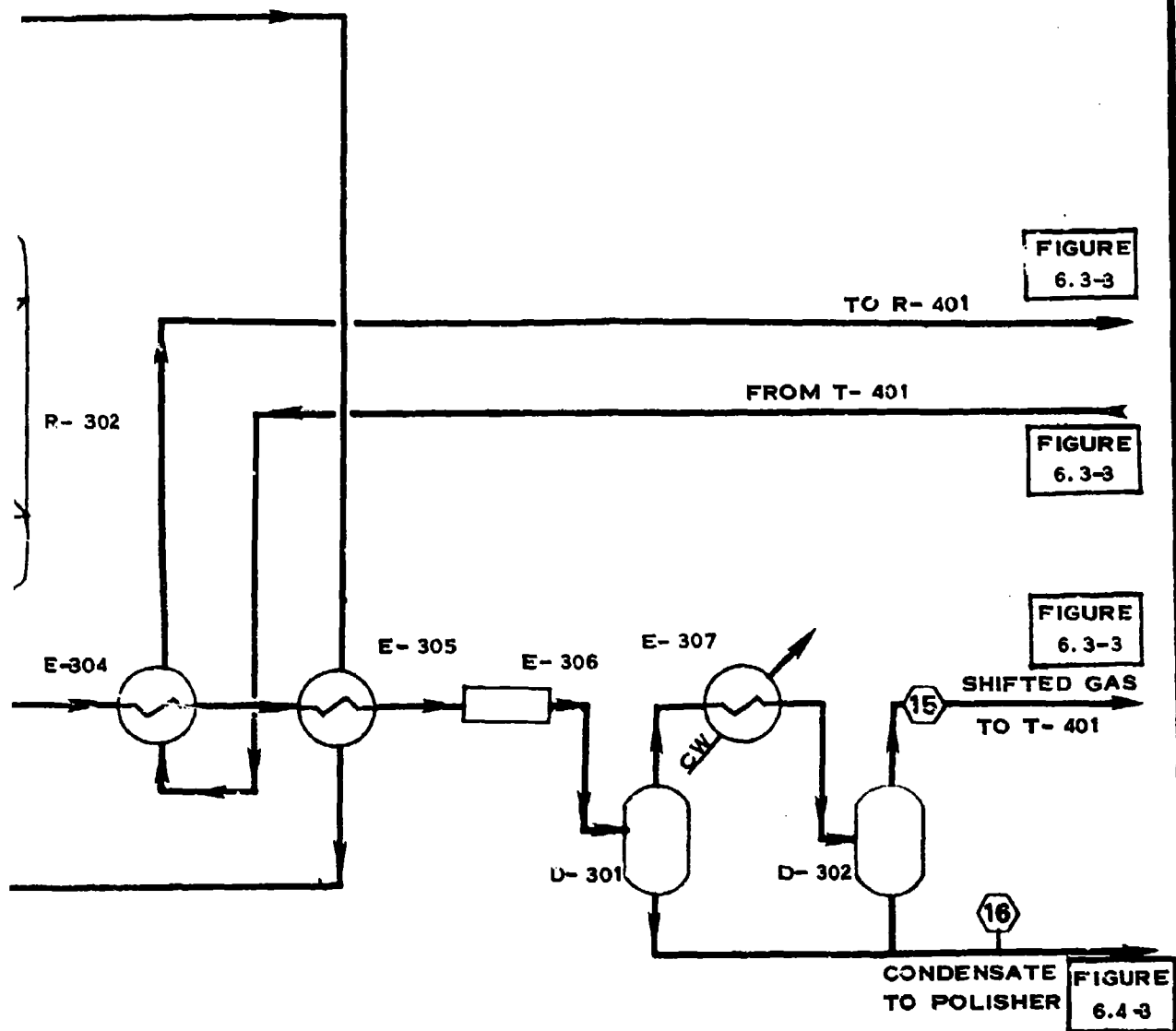


FIGURE  
6.4-1

FIGURE  
6.4-1

D- 301	K.O. DRUM	E- 305	FEED
D- 302	TRIM COOLER K.O. DRUM	E- 306	AIR
E- 301	FEED/EFFLUENT HEAT EXCHANGER II	E- 307	TRIM
E- 302	FEED/EFFLUENT HEAT EXCHANGER I	F- 301	STEAM
E- 303	CO SHIFT STEAM GENERATOR	R- 301	1ST
E- 304	FUEL CELL FEED HEATER	R- 302	2ND



FEED GAS PREHEATER  
 AIR COOLER  
 TRIM COOLER  
 START-UP HEATER  
 1ST CO SHIFT REACTOR  
 2ND CO SHIFT REACTOR

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 PROCESS FLOW DIAGRAM  
 CO SHIFT SECTION  
 FIGURE 6.3-2  
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TABLE 6.3-3

## MASS BALANCE - CO SHIFT SECTION

Stream No. Stream Name	Components	MW	8 Compressed Gas	13 Shift Steam	14 Boiler Feedwater	15 Shifted Gas	16 Condensate
			Lb Mol/hr	Lb Mol/hr	Lb Mol/hr	Lb Mol/hr	Lb Mol/hr
H <sub>2</sub>		2.016	336.50			775.30	
CO <sub>2</sub>		44.010	131.80			571.30	
C <sub>2</sub> H <sub>4</sub>		28.032	2.40			2.40	
C <sub>2</sub> H <sub>6</sub>		30.046	3.50			3.50	
N <sub>2</sub>		28.016	951.50			951.50	
CH <sub>4</sub>		16.032	32.70			32.70	
CO		28.011	462.50			23.70	
H <sub>2</sub> S		34.080	5.55			6.23	
CO <sub>2</sub>		60.070	0.76			0.08	
NH <sub>3</sub>		17.030					
HCN		27.030	0.32				
O <sub>2</sub>		32.000					
Ar		39.946					
H <sub>2</sub> O (Water)		18.016					
H <sub>2</sub> O (Steam)		18.016					
Total Flow			11.0	1,044.90	88.80	31.00	674.22
Total Flow			1,938.58	1,044.90	88.80	2,398.03	674.22
				18,825	1,600		12,147
Pressure			167	175	175	130	120
Temperature			100	371	237	120	

The second stage shift operates at a temperature lower than the first, permitting further reaction of CO to generate more hydrogen and to reduce the CO content to the desired level.

Second stage shift effluent is cooled by preheating anode feed gas in E-304 and preheating raw gas feed to the first stage shift. Additional cooling of the shifted gas to a temperature suitable for its introduction to the Desulfurization Section is accomplished by air and water cooling. Steam condensate resulting from gas cooling is sent to the Thermal Management System. During process startup, gas or oil fired heater, F-301 raises the temperature of the feed gas to the level required for the shift reaction.

#### Sulfur Removal and Recovery

The Sulfur Removal and Recovery Section is shown in Figure 6.3-3 and the Mass Balance given in Table 6.3-4.

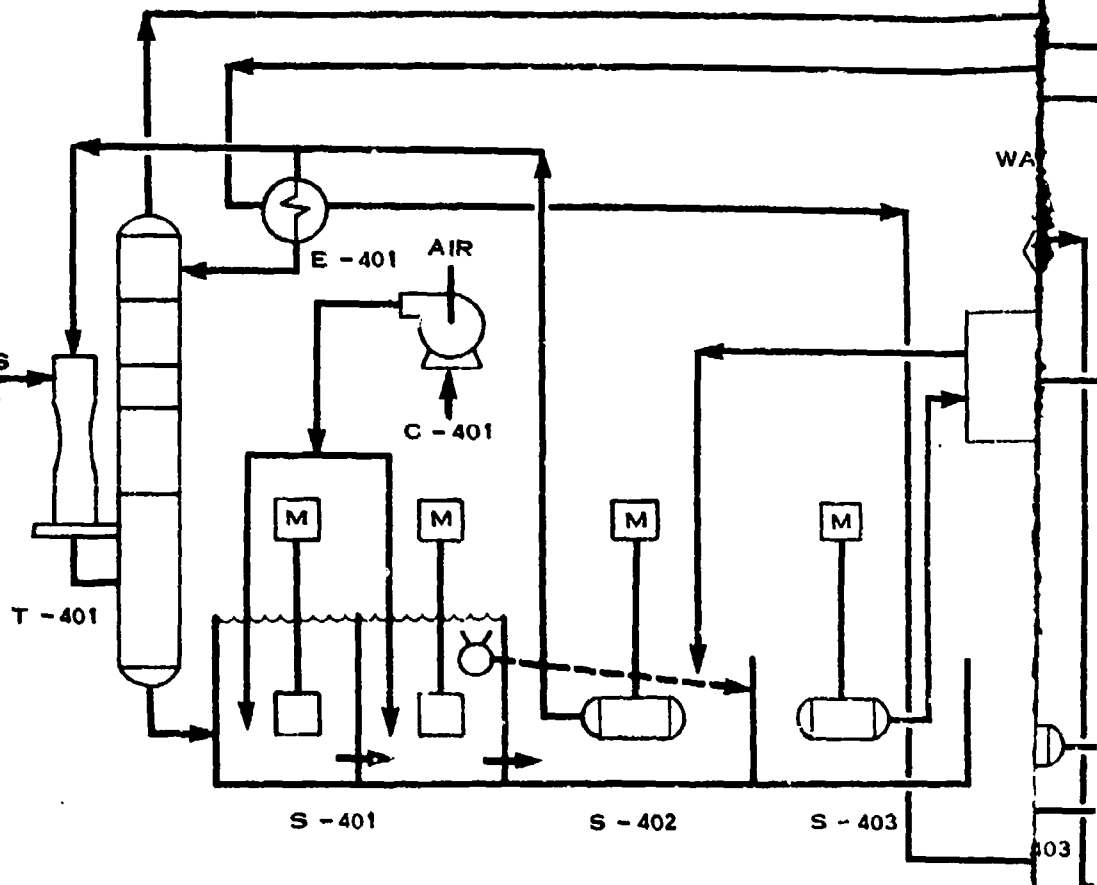
This section is designed to reduce the total sulfur content of the gas to 4 ppm, a level acceptable for the fuel cell operation and for compliance with the sulfur emission levels of the plant. A liquid phase oxidation Stretford Sulfur Removal Process is used for the removal of  $H_2S$  to the required level.

The shifted gas stream is directed to venturi contactor, T-401 which consists of a venturi type jet mixer and an absorber with an alkaline solution containing sodium vanadate. The  $H_2S$  is oxidized by the sodium vanadate to elemental sulfur and water. The solution is sent to oxidizer tank S-401 where by air spraying, and in the presence of anthraquinone disulfuric acid (ADA) the vanadium is oxidized regenerating the alkaline solution and the product sulfur is separated by flotation. The regenerated solution is sent to balance tank, S-402 and recycled to the absorber. The sulfur slurry, separated from the solution, flows to slurry tank S-403 and is separated from other chemicals by filtering and water washing. The sulfur is then reslurried with wash water and heated to the melting point. The molten sulfur flows from decanter, D-401 to the sulfur pit. Chemicals are returned to the system and the wash water discarded.

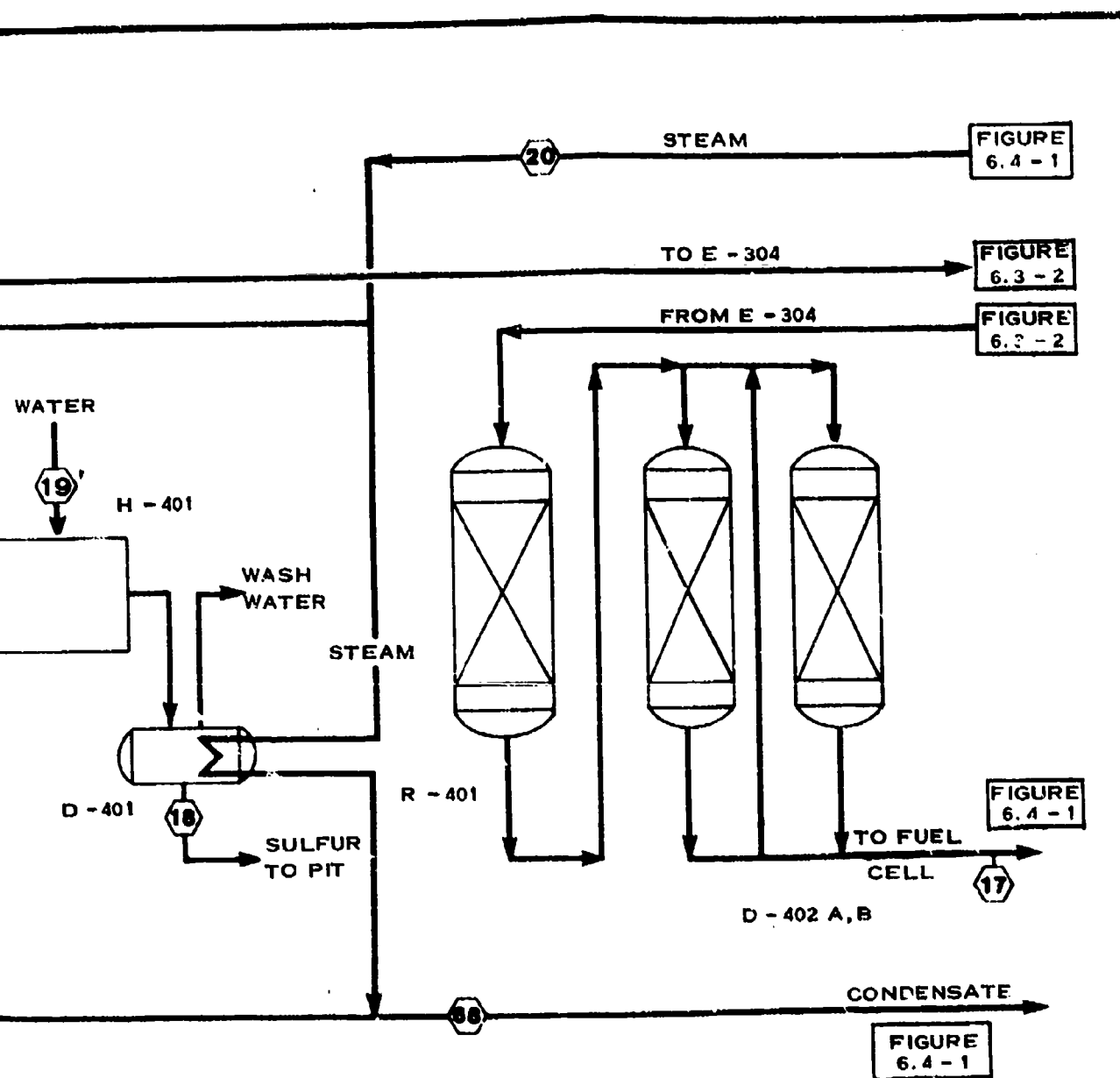
FIGURE  
6.3 - 2

SHIFTED GAS  
FROM D - 302

15



- |              |                                     |
|--------------|-------------------------------------|
| T - 401      | VENTURI CONTACTOR                   |
| E - 401      | SOLUTION HEATER                     |
| C - 401      | AIR BLOWER                          |
| H - 401      | SOLID SEPARATION<br>WASH & RESLURRY |
| D - 401      | SLURRY DECANTER                     |
| R - 401      | HYDROLYSIS REACTOR                  |
| D - 402 A, B | ZnO DRUM                            |
| S - 401      | OXIDIZER TANKS                      |
| S - 402      | BALANCE TANK                        |
| S - 403      | SLURRY TANK                         |



Strea  
Strea

CompC

H2

 $\text{Cu}_2$  $C_2H_4$  $C_2H_6$  $N_2$ 
$$\text{CH}_4$$
CO<sup>2</sup>
$$\text{H}_2\text{S}$$
 $\cos$ NH<sub>4</sub><sup>+</sup>3

HCN

 $0_2$ 

Ar

 $H_2O$  $H_2O$ 

**total**

## Flow

Pres:

## Temp

735

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**PROCESS FLOW DIAGRAM**

**SULFUR REMOVAL AND**

**RECOVERY SECTION**

**FIGURE 6.3-3**

---

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TABLE 6.3-4

MASS BALANCE - SULFUR REMOVAL AND RECOVERY SECTION

D. ame		<u>15</u>	<u>17</u>	<u>18</u>	<u>19</u>	<u>20</u>
		Shifted Gas	Fuel Cell Fuel Gas	Sulfur Product	Wash Water	Steam to Sulfur Slurry
its	MW	Lb Mol/hr	Lb Mol/hr	Lb Mol/hr	Lb Mol/hr	Lb Mol/hr
	2.016	775.30	775.30			
	44.010	571.30	571.30			
	28.032	2.40	2.40			
	30.048	3.50	3.50			
	28.016	951.50	951.50			
	16.032	32.70	32.70			
	28.011	23.70	23.70			
	34.080	6.23	0.0012			
	60.070	0.08	0.0045			
	17.030	-	-			
	27.030	0.32	-			
	32.000					
	39.948					
ter) eam)	18.016					
	16.016	<u>31.00</u>	<u>31.00</u>			
low ow	Lb Mol/Hr	2,398.03	2,391.4	6.30		
	Lb/Hr			202	2,500	640
re ature	Psia	130	120			65
	°F	120	405			298

Product gas leaving the absorber is preheated to 405°F, the fuel cell temperature in the CO Shift Section before being returned to the Gas Desulfurization Section for final polishing.

The final polishing process protects the fuel cell power section from sulfur poisoning in the event of an upset in the sulfur removal plant. It also provides for the removal of residual COS and H<sub>2</sub>S.

The preheated gas is put through a bed of low temperature catalyst in hydrolysis reactor, R-401 to convert COS to H<sub>2</sub>S. The H<sub>2</sub>S is then removed down to the required level by absorption in a zinc oxide bed. The final polished gas is then sent to the fuel cell anode.

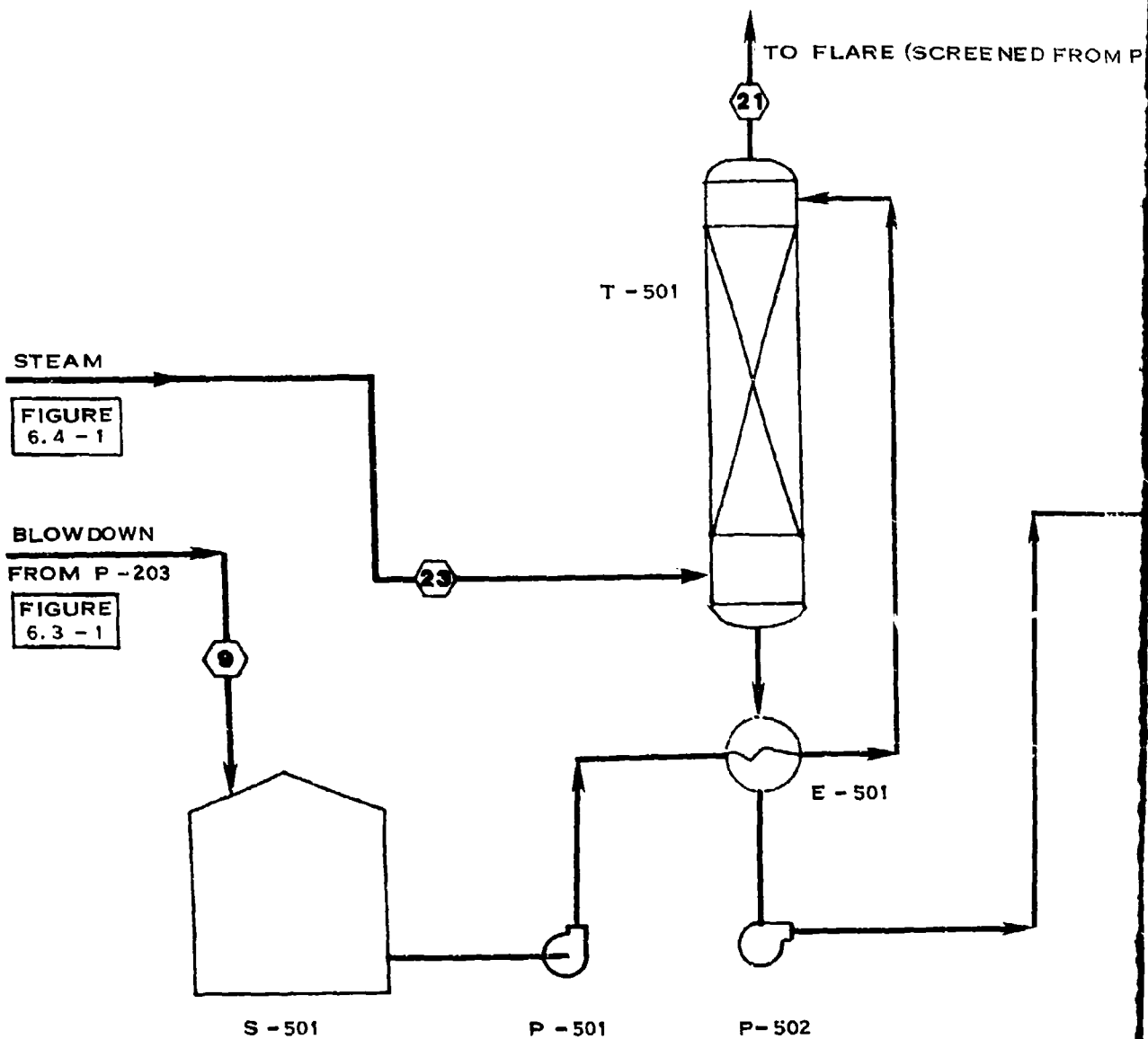
In the Stretford process, there is a by-product fixation of H<sub>2</sub>S into thiosulfate<sup>(7)</sup>. To avoid the accumulation of thiosulfate and thiocyanate, the solution is purged by removing a slip stream which is sent off-site for disposal.

#### Process Condensate Treatment

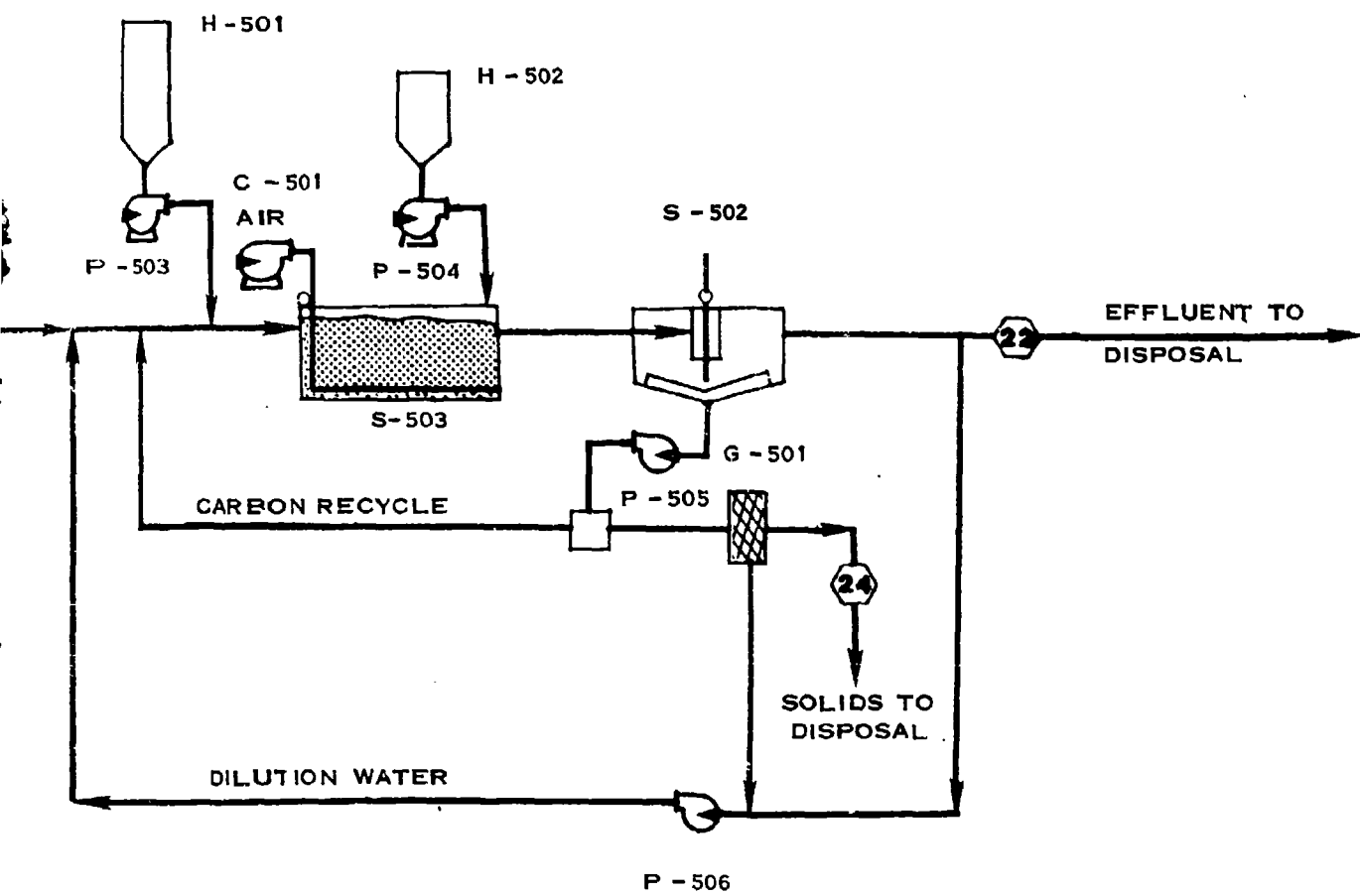
The Process Condensate Treatment Section is shown in Figure 6.3-4 and the mass balance given in Table 6.3-5.

#### Ammonia Stripping

Water containing sour gases (CO<sub>2</sub> and H<sub>2</sub>S) is blown down from tar separator, D-204 of the Gas Cooling and Compression Section to sour water storage tank, S-501. It is then pumped to the Ammonia Stripper where ammonia and some phenols are removed by steam stripping. Steam consumption is reduced by heating incoming feed with stripper bottoms. Overhead vapors from the Ammonia Stripper are flared while stripper bottoms are sent to the Waste Water Treatment Sub-section for further processing.



- |         |                         |
|---------|-------------------------|
| C - 501 | AIR BLOWER              |
| E - 501 | SOUR WATER HEATER       |
| G - 501 | FILTER                  |
| H - 501 | VIRGIN STORAGE TANK     |
| H - 502 | POLYELECTROLYTE STORAGE |
| P - 501 | SOUR WATER PUMP         |
| P - 502 | WASTE WATER PUMP        |



P-503	VIRGIN CARBON FEED PUMP
P-504	POLYELECTROLYTE STORAGE
P-505	CARBON RECYCLE PUMP
P-506	RECYCLE WATER PUMP
S-501	SOUR WATER STORAGE TANK
S-502	SETTLING TANK
S-503	AERATION CONTACT TANK
T-501	AMMONIA STRIPPER

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WASHINGTON D.C. SITE PROCESS FLOW DIAGRAM PROCESS CONDENSATE TREATMENT SECTION
FIGURE 6.3-4
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TABLE 6.3-5

## MASS BALANCE - PROCESS CONDENSATE TREATMENT SECTION

Stream No. Stream Name	Components	20	21	22	23	24
		Process Condensate Blowdown	Ammonia Flare Vent	Wastewater	Steam to Ammonia Stripper	Clarifier Waste
		Lb Mol/hr	Lb Mol/hr	Lb Mol/hr	Lb Mol/hr	Lb Mol/hr
	MW					
H <sub>2</sub>	2.016					
CO <sub>2</sub>	44.010	1.80	1.80			
C <sub>2</sub> H <sub>4</sub>	28.032					
C <sub>2</sub> H <sub>6</sub>	30.046					
N <sub>2</sub>	28.016					
CH <sub>4</sub>	16.032					
CO	18.011					
H <sub>2</sub> S	34.080					
CO <sub>2</sub>	60.070					
NH <sub>3</sub>	17.030	1.12	1.0			
HCN	27.030					
O <sub>2</sub>	32.000					
Ar	39.948					
H <sub>2</sub> O (Water)	18.016	204.90	2.08	192.00	44.96	
H <sub>2</sub> O (Steam)	18.016					
Total Flow	Lb Mol/Hr	207.82	4.88	192.00	44.96	
Total Flow	Lb/hr	3820		3,459	810	114
Solids	Lb/hr					40
Pressure	Psia	17			40	
Temperature	°F	123			267	

## Water Treatment

Water leaving Ammonia Stripping is further treated in the Waste Water Treatment subsection. A Powdered Activated Carbon Treatment (PACT) process is used to produce a waste water adequate for discharge. Raw water entering the system is first diluted by addition of recycled effluent water to adjust the concentration of toxic substances to the requirements of the offsite biological treatment plant. Virgin carbon from H-501 storage tank is added to the diluted waste water as it flows into the aeration contact tank S-503. In the aeration tank the waste water is aerated in the presence of activated carbon, biomass, and inert ash. Mixed liquor dissolved oxygen level is maintained to insure optimum treatment.

To aid in solids settling, polymer from H-502 storage tank is added to the mixed liquor as it flows to the system clarifier S-502. In the clarifier, the solids are settled out. The clarifier overflow is split into two streams. A portion of the clarifier overflow is discharged for disposal. No further treatment of this effluent discharge is required. The remainder of the clarifier overflow is recycled for dilution of incoming feed.

Clarifier underflow solids are continuously recycled to the aeration tank to maintain the high mixed liquor solids concentration. Spent carbon and biomass from the clarifier underflow are filtered before disposal. Filtrate water is combined with effluent recycle for dilution of feed.

### 6.3.3 System Performance

Each plant section is expected to meet or exceed the system availability given in paragraph 2.4 due to the following:

- The technologies used are commercially proven.
- Equipment is selected to provide continuous operation with minimum operator attention and minimum maintenance.

- The design guidelines which are used in the design of each section assure continuous, safe operation. The CO Shift Section performance is based on end of run conditions, where the performance of the catalyst is at its lowest point. But at start of run, when the bed operates with fresh catalyst, the optimum operating conditions can be maintained at lower temperatures, with lower steam consumption.

The sulfur removal plant can remove all  $H_2S$  in the gas resulting from a coal with higher than design sulfur content by increasing the Stretford solution flowrate.

- The availability of the system is increased by providing installed spares for all the pumps in the process.

The electrostatic precipitator (ESP) used for the gas cleaning is the equipment with the highest potential of unscheduled shut-down. It is estimated that in addition to the annual maintenance, the ESP may have four days of unscheduled shut-downs, equivalent to an availability of 95%.

The performance of the Gas Processing System under part load conditions can be assessed as satisfactory. Variations in the gas flow rate greater than 50% turndown can be handled with no adverse effect on product quality, but with some reduction in plant efficiency for reasons indicated below.

The gas cooling and cleaning is achieved by scrubbing with liquids. In order to maintain scrubbing effectiveness, the liquid circulation flow rate and corresponding pumping power must be sustained even though the gas flow rate is reduced.

To prevent destructive gas surging at low flows, the centrifugal compressors must bypass gas from their discharges to their inlets, increasing the compression horsepower per unit of gas processed. The extent of the increase in specific power consumption depends on the compressor selected and will be evaluated during the detail design phase.

The CO shift reactors can accept a turndown below 50% in the gas flow rate. Although the conversion rate improves with reduced space velocity it becomes more difficult to reach the design reaction temperature because reduced gas flow makes less reaction heat available for preheating the feed gas.

The Stretford process has a high degree of flexibility in that it can tolerate wide variations in both gas feed rate as well as  $H_2S$  concentration, especially, when using a venturi contactor (7) without negative impact on the energy consumption, or plant performance.

The ammonia stripping process in the Process Condensate Treating Section requires good contact between the waste water and the live steam. If the liquid flow rate is reduced by more than 30% or more the ammonia stripper can be operated intermittently at full rate, using waste water collected in the Sour Water Storage Tank.

The PACT waste water treatment system also has a high degree of flexibility and can accommodate wide variations in the composition and flow rate of the feed.<sup>(8)</sup> The addition of dilution water gives the system the ability to adjust the composition of the waste water feed to the requirements of the PACT process.

#### 6.3.4 Maintenance

Equipment constituting the Gas Processing Section is selected and applied for maximum reliability which is sustained by a preventative maintenance program. Typical maintenance procedures most of which are applied during the annual scheduled shutdown, are as follows:

- Replacement or repacking of bearings
- Replacement or cleaning of spray nozzles
- Filter and strainer replacement
- Alignment of equipment
- Vibration tests and rebalancing of rotating apparatus if required
- Replacement of broken electrode wires or damaged collector plates of the electrostatic precipitators

Valve and steam trap servicing  
Testing, adjusting, recalibrating and/or replacement of instrumentation and controls  
Tank and vessel cleaning  
Retubing of heat exchangers  
Replacement of tower packing  
Changeout of catalysts, etc.

#### 6.3.5 Technical Risks

The assessment of technical risks associated with this part of the plant indicates that the overall technical risks may be considered low.

The equipment and processes used for Gas Cooling and Cleaning have been used in the coke oven industry in similar applications. Additionally, there are Wellman-Galusha gasification plants in operation which currently use the spray cooling and electrostatic precipitators included in the design of this plant (1). The venturi scrubber used for final cooling and cleaning of the gas is of the type used in existing Texaco coal gasification plants.

The gas compressor can be subject to corrosion and erosion from gas constituents. During detailed design, consideration will be given to avoiding condensation in the compressor and to the selection of suitable materials of construction.

The CO Shift section is not considered to be a high risk, as far as equipment failure and performance are concerned. The COMO sulfur tolerant catalyst, has been used successfully in the chemical industry. Currently there are two Texaco coal gasification projects (TVA and Texas-Eastman) which are using the catalyst without any indication of deterioration. The process conditions do not pose any fabrication problems, comparably sized equipment operating at similar pressures being relatively common. The economic risks associated with the catalyst utilization are not considered high, as failure would occur as a gradual reduction of activity as opposed to catastrophic failure or total inoperability. Risk would reduce the potential for the additional cost of recharging the reactors at greater frequency than expected.

Although not used extensively in coal gasification plants, the Stretford process has been used successfully in the petrochemical industry.<sup>(7)</sup> The process uses relatively simple equipment items such as a venturi scrubber and circulating pumps, which will be provided with installed spares to minimize process disruptions due to possible equipment failure. Reports from operating Stretford plants have in some cases indicated higher chemical consumption than anticipated. Although the reagents used are expensive, the cost of potentially increased consumption is small in terms of overall operating costs for this Section.

The front end process of the condensate treatment section is an Ammonia Stripping unit. Ammonia stripping is a well established process where the variations of ammonia concentration in waste water are controlled by adjusting the steam injection.

The PACT process used in the process condensate treatment is a new advanced biophysical treatment system, which is not yet fully commercialized. Extensive testing of coal gasification waste water was performed in pilot plant operations. Ammonia stripping and phenol extraction failure tests have confirmed that the PACT process provides continuous, reliable treatment, resistant to synfuels facility process upset. Experience has shown that following each organic stress test, the PACT process returned to optimum operation within 2 to 4 days.

By providing excess capacity in the activated carbon feeding system and increased contact time in the aeration tank, the PACT system can be designed to overcome the risks of process upsets.

During startup, the entire system is warmed by circulation of compressed nitrogen. The UTC reformer package can be made operational from the cold standby mode in about 4 hours<sup>(9)</sup> if the rest of the system is hot. A complete changeover from coal gas to natural gas feed will make the fuel cell system operational in 6 to 8 hours.

The installation of facilities to provide natural gas standby service to mitigate the effects of a failure of the coal supply or an unexpected shutdown of the Coal Gasification Section is under consideration.

UTC has designed, manufactured and operated steam reforming units for their 4.8-MW fuel cells. A description of the unit is given in this section.

At the Georgetown University site, natural gas supply is available at 10 psig. The gas must be compressed to 185 psig to allow for pressure drop through the plant for delivery at 105 psig, to the fuel cell anode.

The UTC steam reforming package includes a hydrodesulfurizer, where the sulfur compounds in the gas are converted catalytically to  $H_2S$  and a  $ZnO$  bed where trace amounts of  $H_2S$  are absorbed. This desulfurizing step is necessary for the protection of the reforming catalyst against sulfur poisoning.

The steam reformer consists of a pressure vessel containing vertical tubes where the reaction takes place over the catalyst at about  $1800^{\circ}F$ . Prior to entering the steam reformer, steam and the desulfurized gas is mixed in a 3.7:1 ratio. The endothermic reaction is sustained by heat generated in the upper dome of the vessel by burning depleted anode gas with pressurized air or alternately by diverting a stream of natural gas for combustion in the reformer. The hot exhaust gas from the burner flows over and heats the catalyst filled tubes and is then used in an expander to drive the combustion air compressor.

The reformed methane stream contains  $H_2$ ,  $CO$ ,  $CO_2$ , some unreacted  $CH_4$  and water. To obtain the  $H_2$  and  $CO$  concentrations as specified for the anode feed gas, a  $CO$  Shift reaction is required for the conversion of  $CO$  to  $H_2$ , followed by cooling of the gas and removal of condensate. Suitability of the  $CO$  Shift Section designed for coal gas processing for dual use with natural gas reformer effluent, must be reviewed during the detailed design phase.

6.3.7 References

- 6.3-1 Gas Engineers Handbook, The Industrial Press, 1965
- 6.3-2 Kinetics Technology International Corporation, "Site-Specific Assessment of a 150-MW Coal Gasification Fuel Cell Power Plant" EPRI EM-3162, November 1983
- 6.3-3 Kinetics Technology International Corporation, "Assessment of a Coal Gasification Fuel Cell System for Utility Application" EPRI EM-2387, May 1982
- 6.3-4 C F Braun & Co, "Assessment of Sulfur Removal Processes for Advanced Fuel Cell Systems" EPRI EM-1333, January 1980
- 6.3-5 Wellman-Galusha Gas Producers, Dravo
- 6.3-6 Personal Communication with Dravo Engineers, Inc.
- 6.3-7 Personal Communication with the Ralph M Parsons Co.
- 6.3-8 Personal Communication with Zimpro, Inc.
- 6.3-9 Personal Communication with UTC.

## 6.4 FUEL CELL AND POWER CONDITIONER

### 6.4.1 Fuel Cell System

#### 6.4.1.1 Functions and Design Requirements

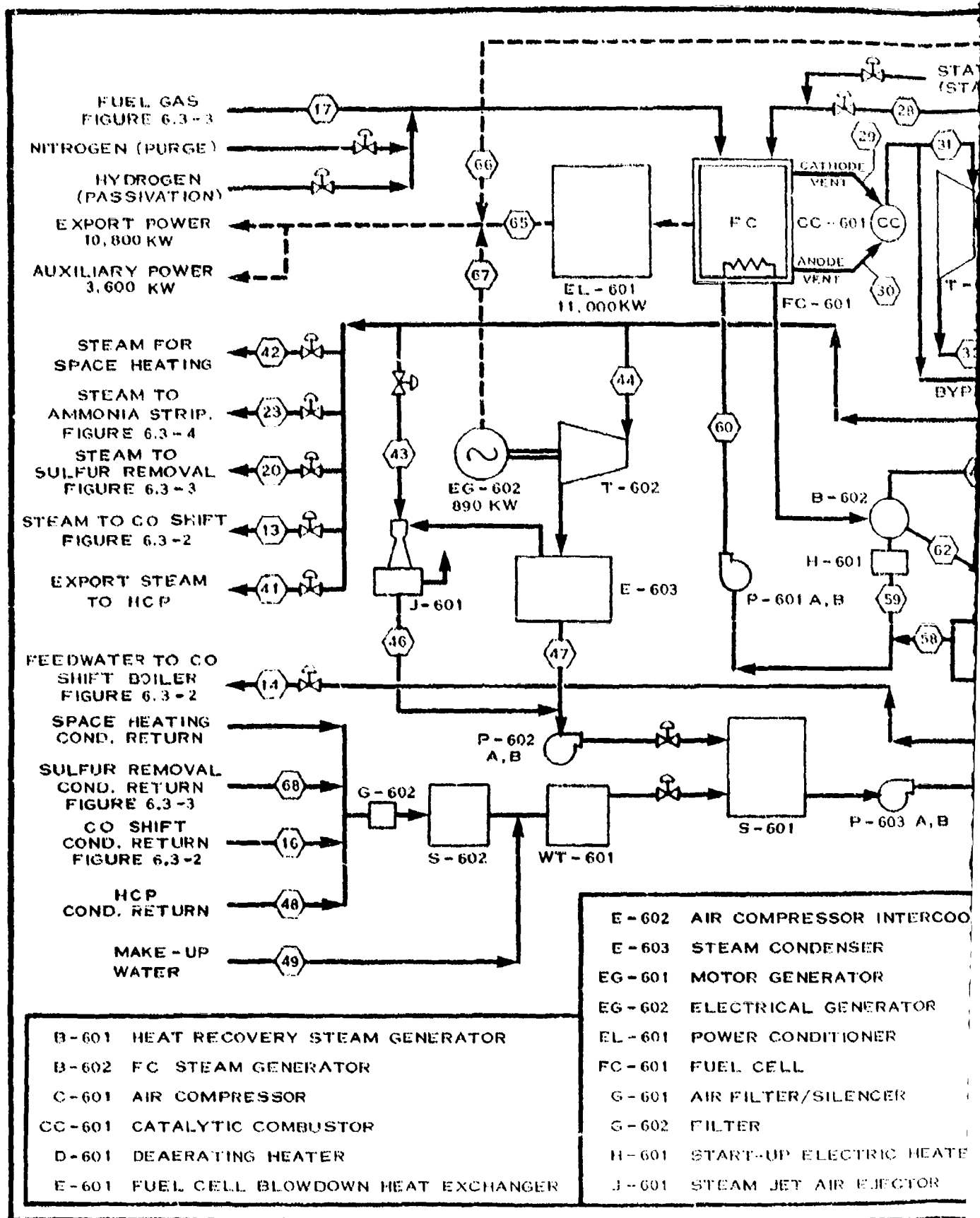
The function of the fuel cell system is to take the hydrogen rich gas stream from the gas processing section, and to convert the energy value of this fuel into useable electric, mechanical and thermal energy. The fuel cell system consists of the fuel cell stacks, catalytic combustor, turbo-expander, compressor and motor-generator.

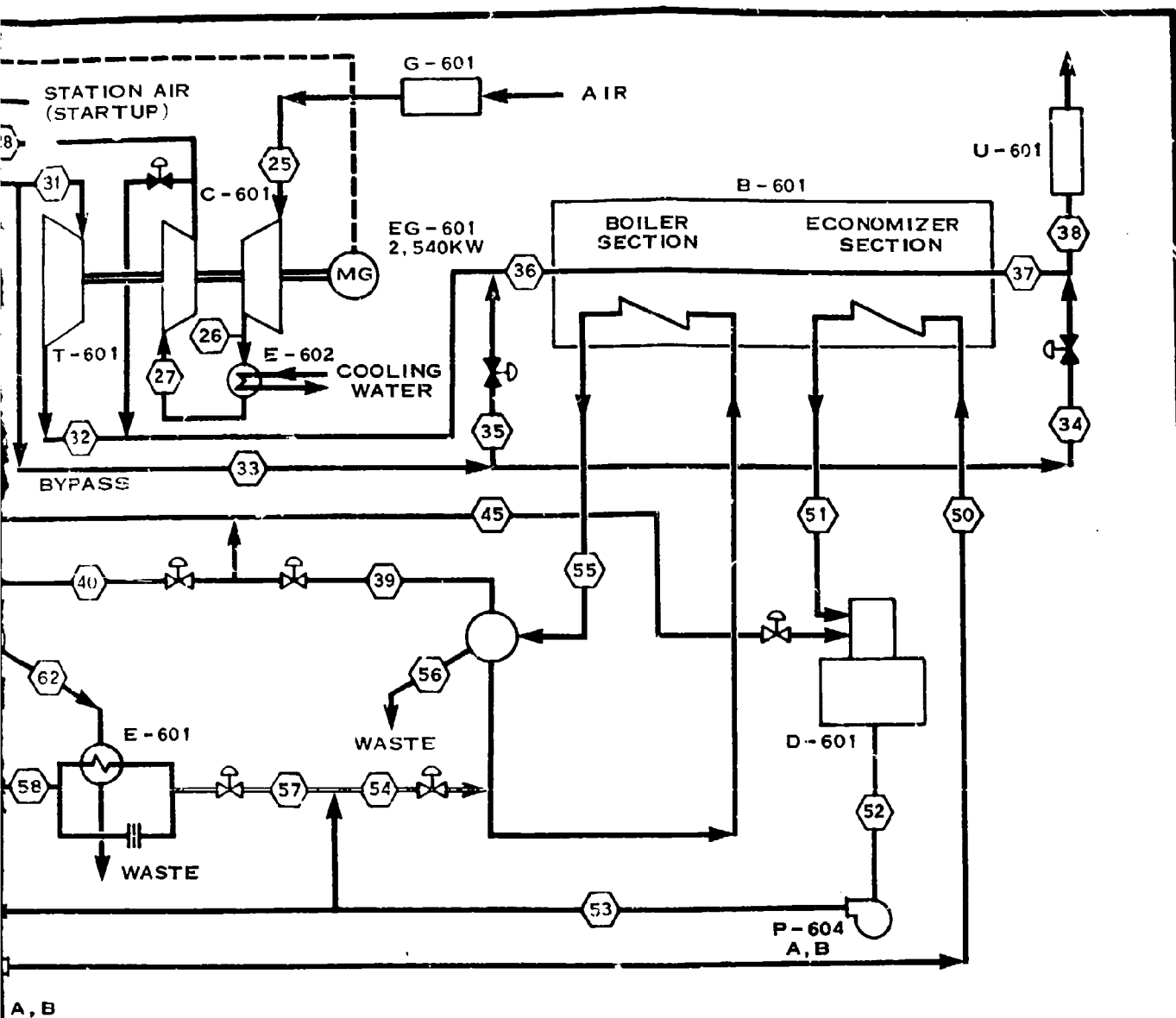
DC power is produced in the fuel cell by the electrochemical reaction of the hydrogen in the gas stream with the oxygen in the compressed air supply. Unregulated DC power is sent to the power conditioner where it is converted to three phase, 60 Hz AC power suitable for connection to the utility grid. Byproduct heat from the fuel cell is removed by a cooling system and utilized in the thermal management system. Energy remaining in the fuel cell vent gases is extracted by a catalytic combustor and an expander turbine. The turbine drives both the compressor supplying air to the fuel cell cathode and a generator.

A flow diagram of the system is shown in Figure 6.4-1.

Criteria for the fuel cell is as follows:

- The fuel cell is a phosphoric acid type of modular design, manufactured by United Technologies Corporation
- Gross DC output is 11.6 MW under design conditions
- Electrical conversion efficiency averages 55% over the design life.
- Fuel cell stacks are replaceable and have a 40,000 hour design life
- Oxygen is supplied to the fuel cell by compressed air
- Fuel cell is water cooled and the byproduct heat recovered
- The fuel cell is capable of operating over a range of 50 to 100 percent of design DC power output
- The fuel cell vent gas effluent meets all federal and local environmental pollution standards.





ERCOOLER	P-601 CIRCULATING PUMP
OR	P-602 CONDENSATE PUMP
	P-603 MAKE-UP WATER PUMP
	P-604 FEEDWATER PUMP
	S-601 CONDENSATE STORAGE TANK
	S-602 CONDENSATE PROVER TANK
HEATER	T-601 GAS EXPANDER
OR	T-602 STEAM TURBINE
	U-601 VENT STACK
	WT-601 MAKE-UP DEMINERALIZER

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**COAL GAS / FUEL CELL / COGENERATION**  
 WASHINGTON D.C. SITE  
 PROCESS FLOW DIAGRAM  
 UTC FUEL CELL AND  
 THERMAL MANAGEMENT SYSTEMS  
**FIGURE 6.4 - 1**  
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Fuel cell performance is dependent on the characteristics of the hydrogen rich anode gas. Anode gas must meet pressure and temperature criteria set by the fuel cell manufacturer, and the purity requirements of Table 6.4-1.

Fuel cell cooling water chemistry is important to prevent corrosion, fouling and blockage of the cooling channels in the fuel cell. Cooling water criteria is shown in Table 6.4-2.

#### 6.4.1.2 System Description

The fuel cell system mass balance is given in Table 6.4-3. Fuel cell parameters are shown in Table 6.4-4. The fuel cell must be purchased from one of the two fuel cell manufacturers with designs near commercialization. The design and configuration of the fuel cell for the Georgetown site will conform to the UTC design<sup>(1)</sup>.

The fuel cell anode receives hydrogen rich gas from the gas processing system. At the design power output of 11.6 MWe DC, the anode of the fuel cell requires 775 lb moles of hydrogen per hour. This results in an anode gas flow of approximately 55,000 lbs/hr of which 32.4% is hydrogen. The fuel cell utilizes 85% of the hydrogen fuel and discharges the remaining hydrogen along with the carrier gas from the anode vent. No gas other than hydrogen undergoes a reaction at the anode.

TABLE 6.4-1

ANODE FEED GAS SPECIFICATION

<u>COMPONENT</u>	<u>LIMIT</u> <sup>(1)</sup>
H <sub>2</sub>	32% min <sup>(3)</sup>
CO	2% max
Olefins	1000 ppm max
Higher Hydrocarbons	1000 ppm max
NH <sub>3</sub>	0.5 ppm max
Cl <sub>2</sub>	0.5 ppm max
H <sub>2</sub> S + COS	5 ppm max
Tars/Oils	.05 ppm max (by wt)
Metal ions	1 ppm max (by wt)
Particulates	30 ug/m <sup>3</sup> max
Pressure	120 psia
Temperature (2)	405°F
H <sub>2</sub> Flow	775 lb moles/hr

Notes:

1. By volume unless otherwise noted
2. Design temperature of cell
3. Design basis. Lower values may be acceptable but will penalize cell performance

TABLE 6.4-2

FUEL CELL COOLING WATER CRITERIA

<u>Parameter</u>	<u>Limit</u>
Suspended Solids	1 ppm
SiO <sub>2</sub>	0.3 ppm
pH	5.0 - 7.0
Conductivity	10 micromho/cm

TABLE 6.4-3

## MASS BALANCE - FUEL CELL SECTION

Stream No. Stream Name	17 Anode Feed (Fuel Gas)	25 Ambient Air Inlet	26 Stage Comp. Exhaust	27 Intercooler Exhaust	28 Cathode Feed (Air)
Components	Lb Mol/hr	Lb Mol/hr	Lb Mol/hr	Lb Mol/hr	Lb Mol/hr
H <sub>2</sub>	775.30				
CO <sub>2</sub>	571.30				
C <sub>2</sub> H <sub>4</sub>	2.40				
C <sub>2</sub> H <sub>6</sub>	3.50				
N <sub>2</sub>	951.50	1,865.30	1,865.30	1,865.30	1,865.30
CH <sub>4</sub>	32.70				
CO	23.70				
H <sub>2</sub> S	0.0012				
COS	0.0045				
NH <sub>3</sub>					
HCN					
O <sub>2</sub>		499.50	499.50	499.50	499.50
Ar		24.10	24.10	24.10	24.10
H <sub>2</sub> O (Water)					
H <sub>2</sub> O (Steam)	31.00	24.10	24.10	24.10	24.10
Total Flow	2,391.4	2,412.90	2,412.90	2,412.90	2,412.90
Total Flow	55,282	69,636	69,636	69,636	69,636
Pressure		14.7	40	40	118
Temperature		60	289	95	361

TABLE 6.4-3 (Cont'd)

Stream No. Stream Name	29 Cathode Exhaust	30 Anode Exhaust	31 Combustor Exhaust	32 Expander Exhaust
	Lb Mol/hr	Lb Mol/hr	Lb Mol/hr	Lb Mol/hr
Components				
H <sub>2</sub>	2.016			
CO <sub>2</sub>	44.010	116.30	639.50	639.50
C <sub>2</sub> H <sub>4</sub>	28.032	571.30		
C <sub>2</sub> H <sub>6</sub>	30.048	3.50	2,816.80	2,816.80
N <sub>2</sub>	28.016	951.50		
CH <sub>4</sub>	16.032	32.70		
CO	28.011	23.70		
H <sub>2</sub> S	34.080			
COS	60.070			
NH <sub>3</sub>	17.030		15.20	15.20
HCN	27.030		24.10	24.10
O <sub>2</sub>	32.000			
Ar	39.948			
H <sub>2</sub> O (Water)	16.016	31.00	911.10	911.10
H <sub>2</sub> O (Steam)	16.016			
Total Flow	2,742.5	1,732.60	4,406.70	4,406.70
Total Flow	70,967	53,954	124,921	124,921
Pressure	115	115	115	16
Temperature	405	405	1,214	664

TABLE 6.4-4  
FUEL CELL PARAMETERS

Parameter	Georgetown Fuel Cell
No. of Fuel Cell Stacks	18
Stack Size	6' dia x 11' 6"
Overall skid ht. (Fuel Cell Skid Only)	16'
Arrangement	3 linear groups of 6 stacks, 3 stacks per skid
Cell Voltage (DC)	.68V
Electrical Conversion Efficiency	55%
Line Voltage (DC)	2100V
Power Output (gross DC)	11.6MWe
Cell Operating Temp/Pres	405°F/120 psia
Design Stack Life	40,000 hours
Fuel (Anode) Input (H <sub>2</sub> )	775 lb moles/hr
Anode Mass Flow Inlet	55,282 lbs/hr
Anode Inlet Temp	405°F
Anode Inlet Pressure	120 psia
Anode Exhaust Temp/Pres	405°F/115 psia
H <sub>2</sub> Utilization	85%
Cathode Inlet Flow	500 lb moles O <sub>2</sub> /hr
	69,636 lbs air/hr
Cathode Inlet Temp/Pres	361°F/118 psia
Cathode Outlet Temp/Pres	405°F/115 psia

TABLE 6.4-4 (Cont'd)

<u>Parameter</u>	<u>Georgetown Fuel Cell</u>
O <sub>2</sub> utilization	70%
Coolant type	water/steam
Coolant flow	$1.67 \times 10^5$ lbs/hr
Inlet Temp/Pres	371°F/250 psia
Outlet Temp/Pres	397°F/240 psia (2 phase)
Heat rejected to coolant	$28.7 \times 10^6$ Btu/hr

Hydrogen molecules that react at the anode, give up two electrons to form two hydrogen ions. These ions migrate through the phosphoric acid electrolyte to the cathode, where they react with oxygen to form water. Oxygen is supplied to the cathode in the form of compressed air. Approximately 70,000 lbs of air flows to the fuel cell cathode. Seventy percent of the oxygen in the air is utilized in the fuel cell. The oxygen depleted air carrying water vapor formed in the fuel cell, exits at the cathode exhaust.

The efficiency and performance of the fuel cell is highly dependent upon the operating pressure and temperature. The manufacturer, UTC, has designed the fuel cell to operate at 120 psia and 405°F. The pressure of the anode gas is maintained by the gas processing section. The temperature of the fuel cell is maintained by cooling water, which carries off the heat generated in the fuel cell by the exothermic reaction of hydrogen. Under design conditions,  $28.7 \times 10^6$  Btu/hr of heat is rejected to the cooling water which circulates between cell plates. The cooling water boils in the cell stack assemblies, exiting as a saturated steam/water mixture at 240 psia. The steam is utilized in the thermal management system. Cooling water flow is 380 gpm.

The fuel cell consists of 18 cell stack assemblies. Each cell stack assembly contains 500 individual cells with an active surface area of 10.6 ft<sup>2</sup> each. The cell stack assembly is housed in a pressure vessel that includes insulation, freeze protection electrical heater and hydrogen leak detection instrumentation. The cell stack assemblies come skid mounted in a group of 3 with prefabricated piping for fuel, air and coolant. The cell stack assemblies are arranged in three linear groups of six. Each group of six stacks is electrically connected in series and the three parallel trains are connected to the electrical protection unit of the power conditioner.

Gases exit the anode containing about 7% unreacted hydrogen along with small amounts of other hydrocarbons that were formed in the coal gasification process. The heat value of these gases is recovered by

combining with the cathode exhaust and burning in a catalytic combustor. The combustor consists of a pressure vessel with a mixing manifold, a gaseous mixing chamber and a length of Pt/Pd catalyst on a ceramic or metal matrix.

A catalytic combustor was chosen because it can burn trace quantities of combustible gases without concern for flame propagation. An alternative design would be to use a flame burner, but natural gas or other fuel would have to be added to maintain the burner flame.

Under design conditions, 29.9 million Btu/hr is released in the combustor, raising the exit gas temperature to 1214°F. The hot gases are expanded in a turbo-expander which drives both the cathode air compressor and a generator. By expanding the gases from 115 psia to 16 psia, the expander develops 7056 shaft horsepower which is sufficient to drive the compressor and a 2.54 MW induction generator. After exiting the expander, the gas stream goes to a heat recovery steam generator (see paragraph 6.5) before venting to the atmosphere. This configuration maximizes the mechanical and electrical energy recovered from the fuel cell vent gases.

The vent gases are the only environmental emissions from the fuel cell system. Pollutants consist of  $\text{SO}_2$ ,  $\text{NO}_x$  and particulates formed in the catalytic combustor. These pollutants are minimized due to the extensive scrubbing in the gas processing system and the relatively low temperature in the catalytic combustor compared to normal gas fired turbine plants. The quantity of pollutants in the vent gases are shown in Table 7-1.

Oxygen is supplied to the fuel cell cathode by a two stage water cooled air compressor that is driven by the expander-turbine. The compressor delivers 15,319 scfm of compressed air to the cell and requires 3,267 shaft horsepower.

#### 6.4.1.3 Performance

The basic performance parameters of the fuel cell system are dc current, dc voltage and reactant utilization. Under design conditions, a supply of 775 lb-moles/hr of hydrogen and 500 moles of oxygen will produce 5520 amps at a pallet (6 stack assemblies) voltage of 2100 volts. These parameters will vary with the load and the age of the cell stacks.

The cell voltage, and hence the electrical conversion efficiency, will vary with the age of the cell stack due to contamination of the electrodes. Voltage will decrease slightly more than 10% over the 40,000 hour design life of the cell. The fuel cell will normally be base loaded, but it can operate at any load between 50% and 100% of design. As load decreases, cell current density decreases and thereby increases the cell efficiency (voltage). Reactant utilization also is a function of both voltage and load. Reactant utilization decreases with load reduction, but this makes the cell stack operate more efficiently since the last cell experiences a richer gas stream. The hydrogen utilization does not change significantly with load, partly because an anode recycle blower provides a feedback mechanism. Oxygen utilization does change significantly with load. The fuel cell stacks will operate at approximately a 10% greater efficiency at 50% load than at 100% load.

Figure 6.4-2 shows the relationship between pallet voltage and dc current.

#### 6.4.1.4 Maintenance

Maintenance for the turbocompressor and generator is standard for rotating equipment with emphasis on periodic check and or replacement of bearings, lubricant, and seals.

Maintenance for the fuel cell stack, centers on replacement of the stack due to degradation of the electrodes. Replacement can be based on a set schedule of operation hours or when stack voltage drops below a minimum set point. The entire stack pressure vessel would be replaced and returned to the manufacturer. The catalyst bed in the catalytic combustor must also be periodically replaced.

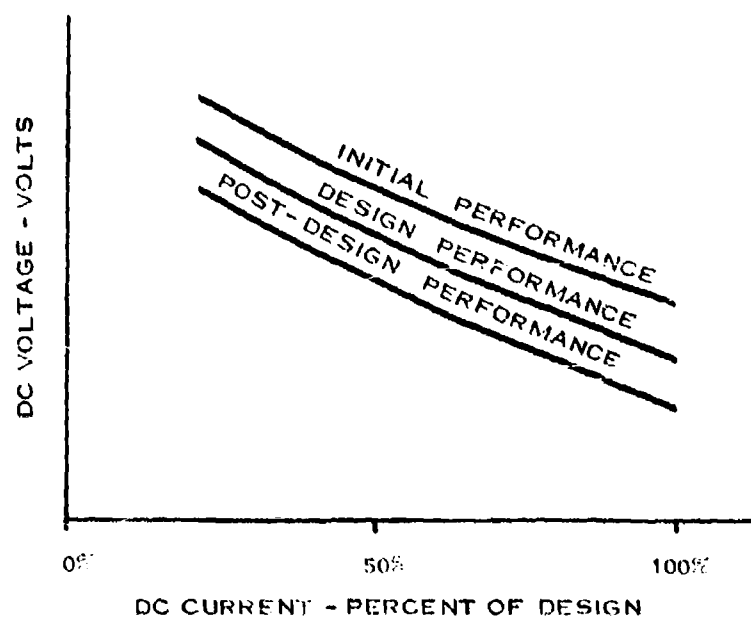


FIGURE 6.4 - 2 EFFECT OF OPERATING TIME ON DC VOLTAGE

Operation and maintenance experience for fuel cells comes from laboratory testing, the ongoing program of field testing small 40 kW on-site fuel cells, and the 4.5 MWe demonstration plant now in operation in Tokyo. The years of laboratory tests indicate that the fuel cell stack will meet the 40,000 hours design life, and the 40 kW program now in its third year has incurred no significant maintenance problems. The Tokyo Electric Power Company (TEPCO) facility has been running since February 1984, and as of March 1985 has accumulated more than 4,500,000 kW-hours of operation. None of the operational and maintenance problems experienced so far by TEPCO have involved the fuel cell stacks. A fuel cell demonstration plant built by Con Edison in New York experienced failure of the fuel cell stacks due to electrolyte leakage while in storage for 3 years. The design of the cell stacks has been improved since the Con Ed stacks were manufactured, and no leakage has been experienced with either the TEPCO stacks or a TVA experimental stack.

#### 6.4.1.5 Technical Risks

Certain technical risks are inherent with the fuel cell since it is not a fully commercialized technology and operating experience is limited. The technical risk is that the fuel cell could fail to perform as specified due to:

- electrolyte leakage
- low cell voltage or voltage fluctuations
- catalyst poisoning
- coolant fouling

The first two risks can be reduced only by the cell design which in turn depends on the quality of the UTC testing and development program, and the feedback from the TEPCO facility.

The plant designer can minimize the risks due to catalyst poisoning and coolant fouling by providing clean anode gas and cooling water. The anode gas clean-up provides for state of the art sulfur removal despite the fact that recent laboratory experience has indicated that this specification could be relaxed.<sup>(2)</sup> The cooling water specification

is more restrictive than originally called for by UTC, based on experience from TEPCO.

#### 6.4.2 Power Conditioner

##### 6.4.2.1 Functions and Design Requirements

The power conditioner is used to convert the dc output from the fuel cell to 3-phase, ac, 60 Hz, for interconnection with the PEPCO system. It also regulates the operation of the fuel cell so as to maintain the required power output. A functional block diagram of a power conditioner is shown in Figure 6.4-3. The key component is the inverter which performs the conversion, maintains synchronization with the PEPCO system and minimizes the generation of harmonics. The power conditioner also contains various safety elements to protect the fuel cell from abnormal voltage conditions and the conditioner itself from upset conditions.

The power conditioner and fuel cell design are linked and must be from the same vendor. The power conditioner is custom designed by UTC and described in Reference 6.4-1. The system offers modular design and electrical characteristics such that it is compatible with a single 11.6 MWe fuel cell. Design criteria for the power conditioner includes:

- The conditioner is rated to have an output of 11 MW ac.
- The conditioner is capable of operation over a range of 30% to 100% of design power output.
- Dc to ac conversion efficiency exceeds 90% over the entire operating range, and 95% under design conditions.
- The conditioner is capable of controlling both real and reactive power
- Ac output conforms to PEPCO requirements

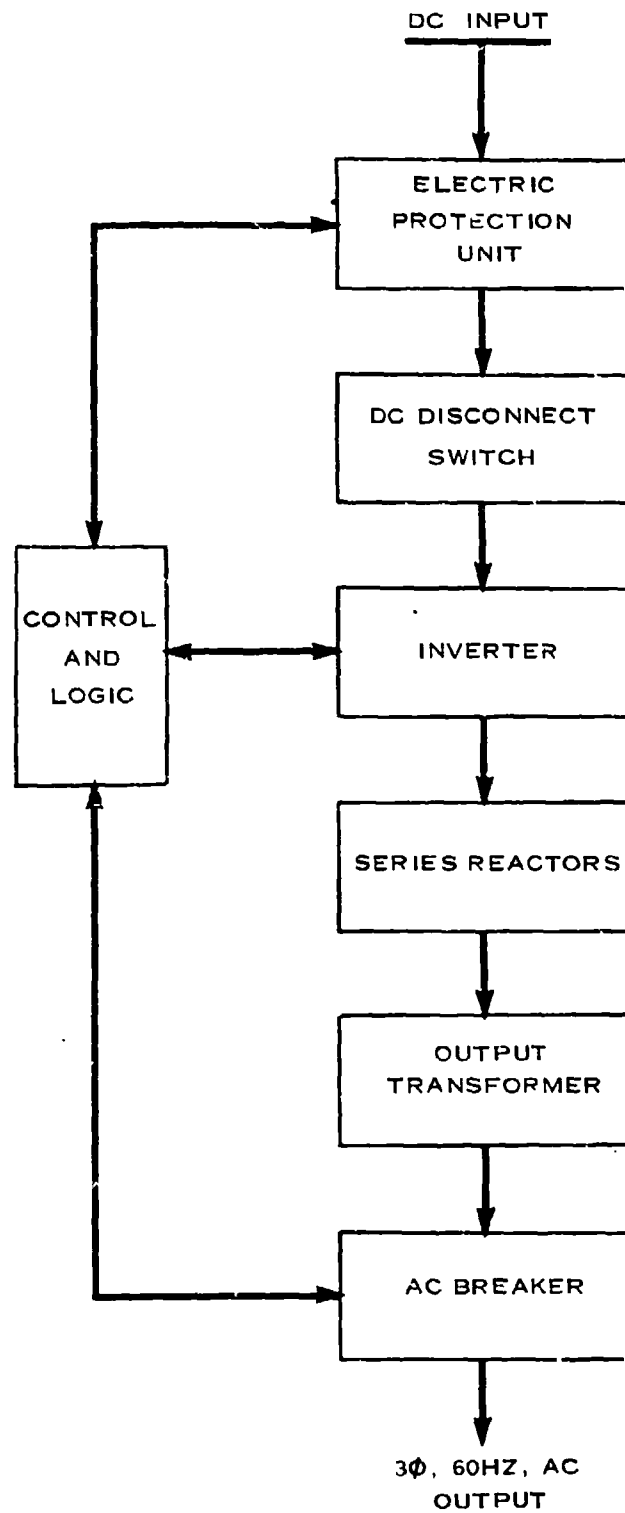


FIGURE 6.4 -3 TYPICAL POWER CONVERTER FUNCTIONAL BLOCK DIAGRAM

#### 6.4.2.2 System Description

The power conditioner consists of an electrical protection unit, dc disconnect switch, inverter, series reactance, output transformer and ac breaker. Each of these performs a specific function as described below. Electrical schematic is shown in Figure 6.4-4.

##### a. Electric Protection Unit

The electric protection unit protects the fuel cell stacks when the system is not producing power and protects against reverse power flow and ground faults.

##### b. DC Disconnect Switch

The disconnect switch disconnects the fuel cell stacks from the inverter. It may be a switch or circuit breaker with provisions for remote and local operation.

##### c. Inverter

The inverter converts the dc output of the fuel cell to 3 phase, 60 Hz ac power. The inverter consists of two power channels for 12 pulse operation and operates over a set range of voltage and power output. All components of the inverters are static, with each inverter having six thyristor arms. Each thyristor arm consists of a series connected stack of thyristors. Thyristors are conservatively rated and each thyristor is protected against voltage and current surges. The firing circuits for the thyristors minimize the difference between the firing angles of the individual thyristors in each arm such that they equally share the blocking voltage and total voltage drop. Commutation circuits are also provided for proper functioning of the inverter. The inverter thyristors are forced cooled. The thyristor arms are modular in construction to facilitate maintenance. Thyristors shall be inverter quality and conform to Reference 6.4-3. Filters are provided for the input and output.

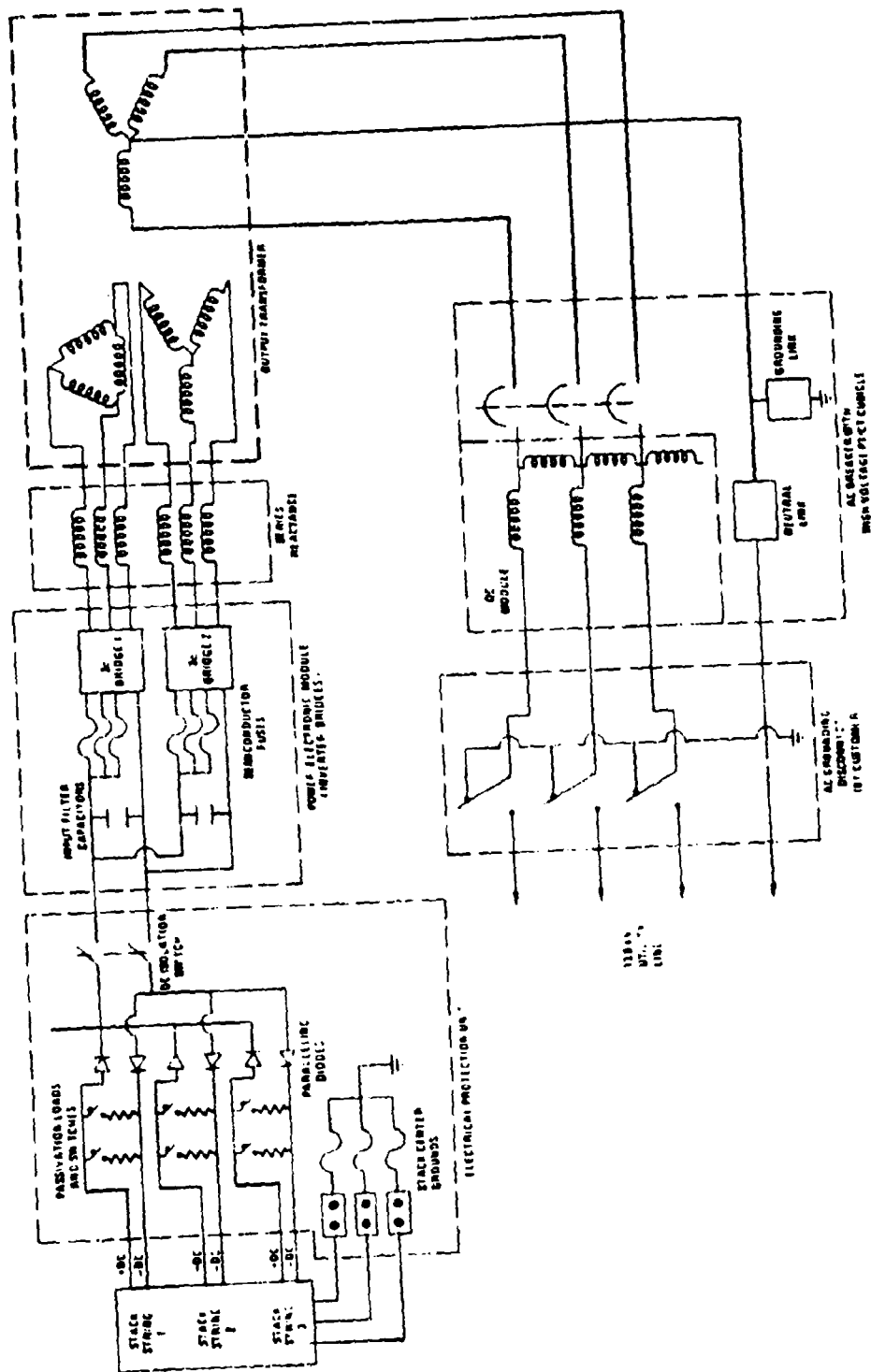


FIGURE 6.4-4 TYPICAL POWER CONVERTER SCHEMATIC

d. Series Reactance

The series reactance functions to control surges, allow for stable control of real and reactive power and reduce output harmonic content. It is conservatively rated for the application and is a dry type self-cooled. The series reactance along with the output transformer places impedance between the inverter bridges and the ac utility line. They also buffer against utility transients.

e. Output Transformer

The output transformer functions to step-up the inverter ac output to a voltage suitable for interconnection to the PEPCO system. The transformer is liquid-filled with natural cooling rated at 11 MVA and 13,800 volts. The transformer for a 12 pulse system is a three winding transformer with a wye connected high voltage winding. One low voltage winding is connected wye and the other delta. A no-load tap changer with 5 full capacity taps (2 above and 2 below nominal), is provided on the high voltage winding. The transformer is supplied with a liquid level indicator, liquid temperature indicator, gas detector, winding hot spot temperature detector, and sudden pressure relay.

f. Ac Breaker

The ac breaker functions to connect the converter to an ac bus. This bus may be at the facility or a PEPCO bus. The breaker is a metal-clad type and may be air-magnetic or vacuum. Protective relays are provided as required by the Georgetown facility and PEPCO, consistent with good industry practice. If the ac breaker is connected to the utility system, synchronizing equipment must be provided.

#### 6.4.2.3 System Performance

The power conditioner converts dc current from the fuel cell to 3 phase ac power at efficiencies exceeding 90 percent over the entire operating load range of the fuel cell modules. Under design conditions of 11.6 MWe gross dc, the power conditioner produces 11.0 MWe ac power at a conversion efficiency of 95%. System performance is shown in Table 6.4-5. Availability is expected to exceed 95%.

Operating characteristics of the power conditioner include:

- . Operator control of output levels
- . automatic startup and shutdown capability
- . Self-regulation of real and reactive power levels
- . Self-limiting operation during abnormal ac or dc conditions
- . Protection of system during out-of-limit conditions and failures.

The operator controls the mode and desired output of the power conditioner in terms of both real and reactive power levels. During automatic operation the power conditioner either attempts to maintain a preset level of output or match grid demand. The conditioner regulates the fuel cell output by sending a signal for the fuel cell controller to change the output.

The power conditioner has two operating modes and one emergency interrupt state. The operating states are: "standby", where the conditioner is armed to accept a load or go into off status; and "load", where the conditioner is fully operational. A further distinction is made between real and reactive power, where impedance is added to the circuit to produce VAR control. The interrupt condition refers to a situation where the utility grid is in an abnormal state in terms of voltage, current, frequency, phase or voltage.

The power conditioner is of modular design and arranged to facilitate access for removal and replacement of components or for bench repair instead of repair in the confined quarters of the cabinet. This improves the quality of maintenance and reduces the time to restore the power conditioner to service after a shutdown.

The key components are the thyristors which can easily be removed and replaced as needed. The high reliability of the system ensures that down time and maintenance are minimal.

#### 6.4.2.4 Technical Risks

The UTC power conditioner is designed specifically for fuel cell applications. Systems employing similar design concepts have proven to be reliable in utility related applications (Reference 6.4-4). One such system is the power conditioner in the 4.5 MW Tokyo plant which has accumulated more than 4,500,000 kW-hours of operation with no reported problems. Using a design based on the above operating experience, the 11 MW power conditioner by UTC should be expected to provide high performance reliability.

Table 6.4-5 - Power Conditioner Performance Characteristics

Real Power

Rated	11 MW net ac at sea level, up to 115°F ambient
Minimum	0 MW net ac (STANDBY)
Operating Range	Continuous between 30% and 100% of rated power

Reactive Power Up to 11 MVAR leading or lagging

Real Power Step Changes

On Load	1 MW/sec. increase
From STANDBY	15 sec. to rated
From HOLD	15 to 60 min. to rated

Reactive Power Step Changes

Minimum to Rated	0.2 second
------------------	------------

Power Form and Quality

Output Voltage	Available to match standard grid voltages between 4 and 69 kV, 3-phase
Output Frequency	Nominal 60 Hz (will follow grid frequency between 61 and 57 Hz)
Harmonics	Voltage total harmonic distortion less than 3% of fundamental, no single harmonic greater than 1% fundamental
Voltage Imbalance and Range	Deliver rated power at 2% line-to-line unbalance + 5% voltage range at rated power (from nominal) +10%, -20% voltage range at reduced power
Fault Current	Limited to 1.1 per unit, RMS for one cycle

6.4.3      References

- 6.4-1      United Technologies Corp., "Description of a Generic 11 MW Fuel Cell Power Plant for Utility Applications". EPRI EM-3161, September 1983.
- 6.4-2      Personal communication with Dr. P. Ross of Lawrence Livermore Laboratory on work performed under EPRI Contract RP-1676-2.
- 6.4-3      ANSI C34.2-1968 (R1973), Practices and Requirements for Semiconductor Power Rectifiers.
- 6.4-4      Ebasco Report PCC-HVDC-001, High Voltage Direct Current (HVDC) Reliability Study, February 13, 1984.

## 6.5 THERMAL MANAGEMENT SYSTEM

### 6.5.1 Functions and Design Requirements

#### Functions

The purpose of the Thermal Management System (TMS) is to convert the thermal and chemical energy flows discharged from the fuel cell into one or more of the following energy forms that can reduce plant operating costs or generate revenue:

1. Steam, hot water and electric power to satisfy the GFC system process demands, thereby lowering plant operating costs, improving plant overall efficiency and minimizing the need to import this energy.
2. Steam for export to help satisfy Georgetown University's Heating and Cooling Plant steam requirements
3. Electric power for export to the electric utility company.

In addition to the above energy sources, tars and oils produced in the coal gasification and separated in the Gas Processing Section, are for the basis of this study considered to be sold.

#### Design Requirements

TMS design requirements are based on interfacing with the following configuration of UTC fuel cell and auxiliary equipment: (1) water cooled, nominal 11 MW UTC fuel cell, consisting of a closed pumping loop with steam drum for the production of saturated steam and (2) a catalytic combustor receiving fuel cell anode and cathode vent gases and subsequent expansion of exiting combustion products through a gas expander-air compressor-motor/generator set.

The TMS receives a fuel cell cooling system heat load of  $28.7 \times 10^6$  Btu/hr, conveyed by circulating through the fuel cell; 167,000 lb/hr of high purity water and discharging to the TMS as 240 psig, 397°F saturated steam and 5% blowdown water. Makeup water to this system is demineralized, deaerated and heated to at least 242°F.

The gas expander exhausts gas at the rate of 124,900 lb/hr at 664°F and 16 psia. Properties of this gas mixture include a molecular weight of 28.35 and specific heat of 0.283 Btu/lb-F.

The TMS is designed to meet the following plant process steam, hot water, electric power and export steam requirements:

1. process thermal and power demands, including
  - CO shift boiler steam
  - sulfur slurry steam
  - ammonia stripper steam
  - CO shift boiler feedwater heating
  - auxiliary electric power
2. export steam to the Georgetown University Heating and Cooling Plant (HCP) at least sufficient for compliance with the PURPA requirement that the useful thermal energy output of a qualifying topping cycle cogeneration facility be no less than 5% of the total energy output during any calendar year.
3. export electric power to the electric utility grid.

The above process and GU HCP requirements are listed in Table 6.5-1.

The present GU HCP steam demand is sufficiently high to utilize all of the thermal energy generated by the TMS. However, since this demand is satisfied utilizing inexpensive cogenerated steam produced by GU's 100,000 lb/hr coal-fired atmospheric, fluidized bed (AFB) boiler, it is more economic that TMS steam export to GU be the minimum necessary to meet PURPA requirements, and that remaining steam, after satisfying plant process requirements, be used to produce electric power.

Thermal energy contained in the gas expander exhaust flow is recovered in a heat recovery steam generator (HRSG), designed to generate steam at the same pressure and temperature as fuel cell cooling system steam so that the outputs may be combined for input to a steam turbine-generator.

In addition to the boiler section, the HRSG shall include an economizer section to preheat TMS makeup water and further lower the gas temperature prior to discharge.

Excess steam shall be expanded through a condensing type steam turbine-generator for maximum electric production.

TMS equipment shall be designed for the following expected operating modes:

<u>Mode</u>	<u>Equipment Status</u>
Normal Load	Fuel cell at 100% power; Normal process and export steam loads
Maximum Load	Fuel cell at 100% power; Minimum process and no export steam load
Half Load	Fuel cell at 50% load
Steam Turbine Generator Out of Service <sup>(1)</sup>	Fuel cell at 100% load HRSG partially bypassed
Gas Expander Out of Service <sup>(1)</sup>	Fuel cell at 50% load; HRSG partially bypassed

Notes:

1. Includes reduced load on generator

TABLE 6.5-1  
TMS PROCESS CRITERIA

I. Gasifier-Fuel Cell Requirements

A. Process Steam

CO Shift Boiler - 18,825 lb/hr, 175 psia, 371°F  
Sulfur Slurry - 640 lb/hr, 65 psia, 298°F  
Ammonia Stripper - 810 lb/hr, 40 psia, 267°F

B. Process Feedwater

CO Shift Boiler - 1,600 lb/hr, 175 psia, 237°F

C. Process Condensate Return

Gas Processing - 12,147 lb/hr, 130 psia, 120°F

D. Auxiliary Electric Power - 3,100 kW

TABLE 6.5-1 (Cont'd)

## II. Georgetown University Steam Demand

	<u>Chiller Turbine,</u> <u>lb/hr @ 290 psia</u>	<u>HCP Auxiliaries,</u> <u>lb/hr @ 290 psia</u>	<u>Campus Heating</u> <u>lb/hr @ 140 psia</u>	<u>Total</u> <u>lb/hr</u>
January	0	12,000	62,000	74,000
February	0	4,000	56,000	60,000
March	0	6,000	58,000	64,000
April	4,000	5,000	38,000	47,000
May	36,000	6,000	29,000	71,000
June	63,000	11,000	22,000	96,000
July	78,000	10,000	12,000	100,000
August	78,000	10,000	12,000	100,000
September	51,000	12,000	22,000	85,000
October	29,000	20,000	29,000	88,000
November	11,000	13,000	41,000	65,000
December	0	8,000	58,000	66,000

## III. PURPA Export Thermal Requirement for a Cogeneration Facility

2,000 lb/hr steam based on 5% of the total energy output of 11.5 MW.

### 6.5.2 System Description

The primary energy output of the fuel cell is the net 11 MW electric AC power produced by the fuel cell power conditioner (EL-601). However, the fuel cell also discharges additional significant energy flows in the form of (1) thermal energy discharged to the fuel cell cooling water system and (2) chemical, pressure and thermal energies vented at the fuel cell anode (fuel gas) and cathode (air). The Thermal Management System receives these additional energy flows and converts them to useful thermal, mechanical and electric power supplies that are distributed to meet plant process needs, thus reducing plant operating expenses, or exported to generate revenue.

TMS process flow diagram and stream parameters are given in Figure 6.4-1. This diagram incorporates process thermal and PURPA export steam loads given in Table 6.5-1. TMS equipment is described in Appendix A. Refer to Table 6.5-2 for stream flows and conditions.

The TMS, as shown Figure 6.4-1, consists of the following major functional areas: fuel cell cooling water; catalytic combustor and gas expander; heat recovery steam generator; steam distribution piping; condensing steam turbine and condenser; and condensate storage. These functions are described below:

#### Fuel Cell Cooling Water

The fuel cell cooling water system removes heat released by the fuel cell exothermic electro-chemical reaction by the forced circulation of condensate through the fuel cell stacks. Condensate exits the equipment as a two-phase mixture which is conveyed to a steam drum where the liquid and steam phases are separated. Steam flow at full load is approximately 29,000 lb/hr. Steam is discharged to TMS steam piping via a pressure control valve which maintains a constant steam drum saturation pressure/temperature of 240 psia/397°F. In case of control valve failure a safety valve protects the system and fuel cell from over pressure.

TABLE 6.5-2

MASS BALANCE - THERMAL MANAGEMENT SYSTEM

Stream No. Stream Name		<u>33</u> Expander Bypass	<u>34</u> HRSG bypass	<u>35</u> Bypass to HRSG	<u>36</u> HRSG Inlet	<u>37</u> HRSG Outlet	<u>38</u> Vent Stack
Flow	Lb/Hr	0	0	0	124,921	124,921	124,921
Pressure	Psia	115	16	16	16	15	15
Temperature	°F	1,214			664	259	259
Enthalpy	Btu/Lb						

Stream No. Stream Name		<u>39</u> HRSG Steam	<u>40</u> FC Cooling Steam	<u>41</u> Export Steam	<u>42</u> Heating Steam	<u>43</u> SJAЕ Steam	<u>44</u> Turbine Steam
Flow	Lb/Hr	9,076	29,015	2,000	0	160	14,611
Pressure	Psia	240	240	230	230	230	230
Temperature	°F	397	397	394	394	394	394
Enthalpy	Btu/Lb	1,200.6	1,200.6	1,200.6	1,200.6	1,200.6	1,200.6

TABLE 6.5-2 (Cont'd)

Stream No. Stream Name		45 Deaerator Steam	46 SJA Condensate	47 Condenser Condensate	48 Return Condensate	49 City Water Makeup	50 Economizer Inlet
Flow	Lb/Hr	1,045	160	14,611	2,000	10,993	40,551
Pressure	Psia	230		2			100
Temperature	°F	394		125			100
Enthalpy	Btu/Lb	1,200.6		93			68

Stream No. Stream Name		51 Economizer Outlet	52 Deaerator Outlet	53 Feedwater Makeup	54 HRSG Makeup	55 HRSG Blr Outlet	56 HRSG Blr Blowdown
Flow	Lb/Hr	40,551	41,596	39,996	9,530		454
Pressure	Psia	85	26	315	315	240	240
Temperature	°F	217	242	242	242	397	397
Enthalpy	Btu/Lb	185	211	211	211		372

TABLE 6.5-2 (Cont'd)

Stream No. Stream Name		57 FC Cooling Makeup	58 FC Cooling Makeup	59 FC Drum Outlet	60 FC Cooling Inlet	61 FC Cooling Outlet	62 FC Drum Blowdown
Flow	Lb/Hr	30,466	30,466	136,534	167,000	167,000	1,451
Pressure	Psia	315	240	240	250	240	240
Temperature	°F	242	249	397	371	397	397
Enthalpy	Btu/lb	211	218	372	344	516	372

Stream No. Stream Name		63 Blowdown HE HS Outlet	64 Blowdown HE CS Outlet	65 Power Conditioner	66 Generator EG-601	67 Generator EG-602	68 Return Condensate
Flow	Lb/Hr	1,451	3,000	-	-	-	640
Pressure	Psia	230	230	-	-	-	-
Temperature	°F	252	314	-	-	-	-
Enthalpy	Btu/Lb	221	284	-	-	-	-
Power	kW	-	-	11,000	2,540	890	-
Volts	V	-	-	-	-	-	-

A portion of the liquid phase, equal to five (5) percent of the steaming rate, is discharged from the system as blowdown. The remaining condensate, plus makeup water to compensate for steam and blowdown losses, is recirculated to the fuel cell by one of (2) 100% fuel cell cooling water pumps (P-601A,B).

For protection of fuel cell components from contamination by cooling system corrosion products, blowdown and makeup water chemistry specifications must be held to within strict limits. To minimize dissolved oxygen contained in the makeup water it is deaerated and heated to 242°F in a direct contact deaerating heater (D-601). Deaerator steam supply is from the TMS steam header.

Makeup water flow is regulated based on steam drum water level. A portion of the makeup water flow is passed through a blowdown heat exchanger (E-601) to recover some of the blowdown heat prior to its discharge to waste treatment.

The fuel cell cooling system also contains an electric heater (H-601) which raises the system operating temperature during fuel cell start-up.

#### Heat Recovery Steam Generator

Gas expander exhaust gas temperature at 664°F is used to generate steam and hot water in a heat recovery steam generator (HRSG) (B-601). The HRSG consists of boiler and economizer sections. The boiler section, operating at the same steam pressure and temperature as the fuel cell cooling system, 240 psia and 397°F, generates a steam flow of approximately 9,100 lb/h. Boiler blowdown water equals 5% of the steaming rate and is discharged to waste treatment.

Makeup water to the boiler circulating loop is pumped by one of two full capacity feedwater pumps (P-604A, B) from deaerating heater D-601 which deaerates and preheats the makeup water to 26 psia/242°F. Utilizing boiler steam, the direct contact deaerating heater raises the makeup water temperature to saturation temperature while scrubbing the water of non-condensable gases which are vented. The deaerating heater has a

condensate storage volume of at least 10 minutes to assure a continued supply of boiler feedwater in case the flow of entering makeup water is interrupted.

The exhaust gas leaving the HRSG boiler section is further cooled to about 260°F in the HRSG economizer section. Makeup water from the condensate storage tank (S-601) is pumped through the economizer where it is heated to within about 25°F of deaerator saturation temperature.

Although the normal full load gas inlet temperature is about 664°F, the HRSG is designed to accept higher gas temperatures during off normal operation when all or a portion of the gas expander flow is bypassed to the HRSG inlet. For example, if generator G-601 trips, HRSG gas inlet conditions at full load steaming rate, are about 87,000 lb/hr at 847°F. Furthermore, if gas expander T-601 is out of service (air compressor C-601 being driven by EG-601), HRSG gas conditions are about 52,000 lb/hr at 1214°F.

Gas exiting the HRSG economizer discharges to the environment through vent stack U-601. Although stack height is restricted to building height the exhaust gas velocity is sufficient for plume dispersion.

#### Steam Distribution Piping

Total TMS boiler steam flow produced in fuel cell cooling water and HRSG steam drums is about 38,100 lb/hr which is piped to the various process steam users including 2,000 lb/hr export steam flow to Georgetown University's campus heating system. After satisfying these loads (see Table 6.5-1) the remaining steam flow of 14,600 lb/hr is conveyed to a steam turbine-generator for power generation.

The steam pressure to each of the process steam loads is regulated by a pressure control device at the point of use.

#### Steam Turbine Generator/Condenser

During normal operation about 14,600 lb/hr steam at 230 psia is expanded through a multi-stage steam turbine (T-602) which drives an electric generator (EG-602) to produce a net output of 890 kW.

Due to the variability in steam demands (for example, ammonia stripper and sulfur slurry heating, and the CO shift steam load which depends on the specific coal delivered), the turbine generator is designed for 130% of normal steam flow or 19,000 lb/hr. The corresponding generator output rating, including 5% margin, is 1215 kW.

Turbine exhaust steam is condensed in a two pass single pressure condenser (E-603) which achieves a turbine exhaust pressure of 4 in. Hga at rated steam flow. The condenser also receives miscellaneous TMS condensate drains (except blowdown) and steam vents. Condenser tubes are stainless steel for maximum corrosion resistance. The condenser hotwell provides a minimum of 5 minutes of condensate storage. One of (2) 100% condensate pumps (P-602A, B) return the condensate to a condensate storage tank (S-601).

Non-condensable gases are evacuated from the condenser by a two-stage steam jet air ejector, (J-601). Condensed ejector steam is discharged to the suction of the condensate pumps.

#### Condensate Storage

Condensate makeup to TMS equipment is stored in a condensate storage tank (S-601) which receives about 14,800 lb/hr from the condensate pumps (P-602) and 25,800 lb/hr from water treatment system (WT-601) consisting of process and export condensate returns plus about 11,000 lb/hr city water makeup which compensates for steam and condensate consumed in process operations.

Condensate storage tank minimum storage volume equals 12 hours of full load operation without water treatment makeup.

One of (2) 100% capacity makeup water pumps (P-603A, B) supply condensate to the HRSG economizer inlet. Makeup water flow is regulated based on deaerator (D-601) water level.

### 6.5.3 Performance

The TMS is designed to produce steam at 240 psia and 397°F over the 50-100% normal operating range. Full load performance is shown on process flow diagram Figure 6.5-1.

Fuel cell cooling system steam production is a function of the fuel cell power conditioner load setpoint and corresponding fuel cell efficiency. Since fuel cell efficiency increases as load decreases (fuel cell stacks operate at approximately 10% higher efficiency at 50% than at 100% load), steam production tends to drop more rapidly than does fuel cell power output. For example, at 50% GFC plant load, based on an increase in fuel cell efficiency from 50% at full load to 60% at half load, it is estimated that steam flow will be 40% of full load output.

However, the converse is true for the HRSG where steam production reduces at a rate that is less than the decrease in fuel cell power. For example, assuming that HRSG inlet gas flow is proportional to fuel cell load but temperature remains constant, at 50% load HRSG steam generator will be approximately 57% of full load output. Gas temperature approach to steam saturation temperature is about 13°F (based on a 50°F design pinch point temperature) indicating that nearly all of the HRSG evaporation section heat transfer surface area is utilized for steam production.

At 50% load the HRSG exhaust temperature decreases to approximately 200°F. Being above the dew point temperature of 142°F, no condensation (with potential corrosion) should occur.

In addition to normal operation between 50 to 100% load, the TMS can operate during such abnormal modes as either induction motor/generator EG-601 or gas expander T-601 being out of service.

If load on the turboexpander shaft reduces for example, due to the motor generator being out of service, 66,900 lb/hr of the total combustor output of 124,900 lb/hr at 1214°F bypasses the expander to prevent an overspeed condition. Of this 66,900 lb/hr, 29,000 lb/hr mixes with the expander exhaust, the gas mixture entering the HRSG at 847°F and 37,900 lb/hr bypasses the HRSG. The mixture of HRSG exhaust and bypass results in a stack temperature of 536°F.

If gas expander T-601 is out of service the catalytic combustor exhaust flow bypasses the expander with 52,000 lb/hr supplied to the HRSG, and 73,000 lb/hr to the stack resulting in a stack gas temperature of about 813°F.

The electric output of condensing turbine-generator EG-602 depends on the throttle steam flow available from fuel cell cooling and HRSG boiler drum outputs after the various process and export steam demands are satisfied. The turbine, generator, steam condenser E-603 and condensate pumps P-602A, B, are sized for 130% of normal expected load.

#### 6.5.4 Maintenance

Equipment constituting the TMS is of proven reliability which is sustained during the plant life by well established maintenance procedures, most of which are applied during the annual scheduled shutdown.

Included among these procedures are inspection and replacement (or plugging) of HRSG and steam condenser tubes, relubrication or replacement of bearings shaft seal replacement, comping realignment, valve and damper maintenance, calibration and adjustment of controls, including turbine governor, vibration check and rotor balancing, replacement of cooling tower fill, etc.

#### 6.5.5 Technical Risks

Because the TMS utilizes proven equipment, there are no technical risks beyond those normally assumed by commercial ventures in mature technologies.

## 6.6 Auxiliary Systems

### 6.6.1 Electrical

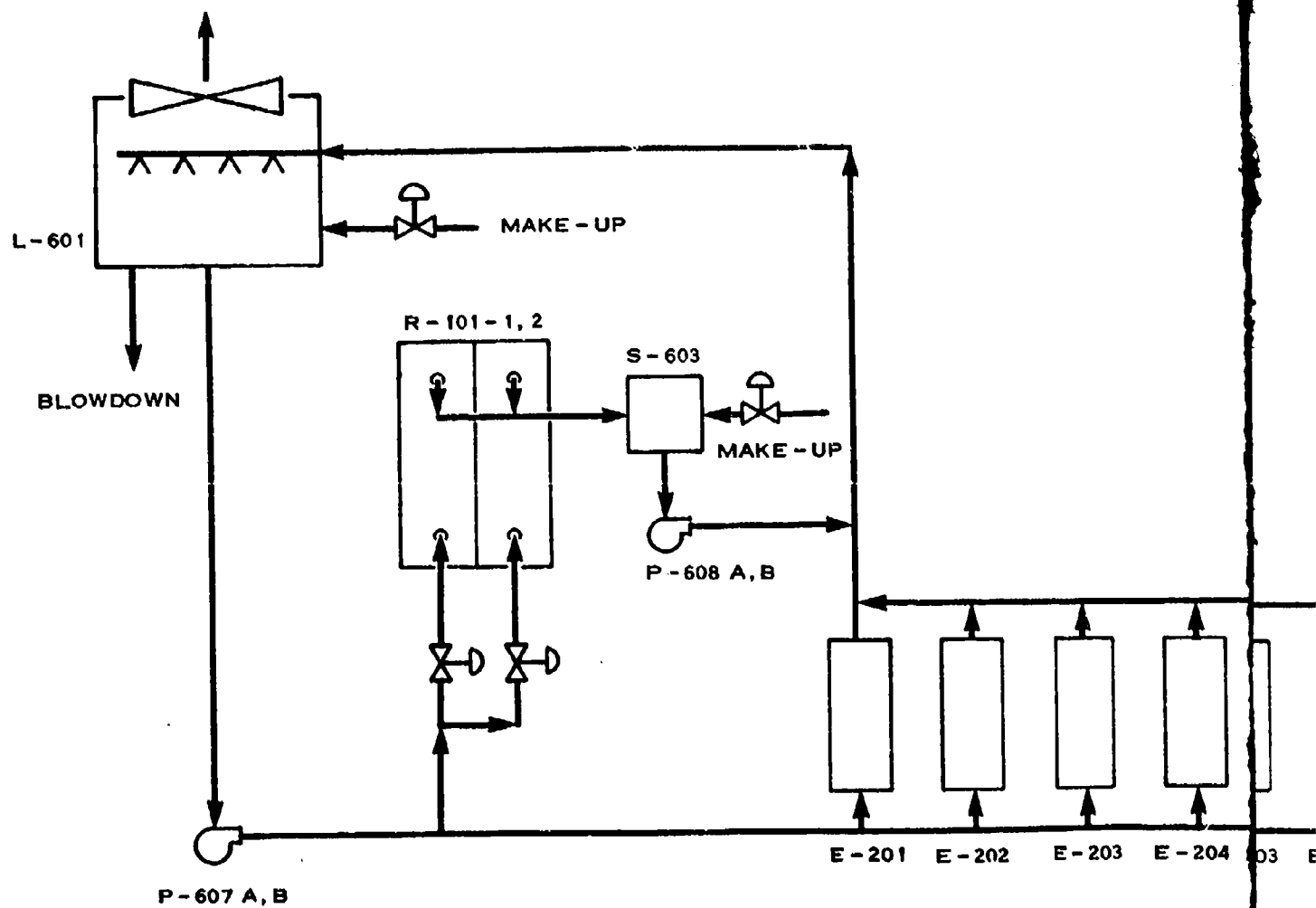
Electrical power for auxiliaries including lighting, is provided by an auxiliary power transformer. This may be a dry-type or liquid-filled transformer with natural cooling (e.g., OA or AA). The low voltage winding shall be suitably rated for the electrical auxiliaries (preferably 480 Vac, 30 60Hz). Additional dry-type transformer will be provided for 208Y/120 Vac. Auxiliary loads will be supplied by a variety of devices (e.g, metal-enclosed switchgear, motor control centers and panelboards) as required by the load. In addition, an uninterruptible power supply (UPS) will be provided for critical loads, control and instrumentation. The UPS shall consist of an inverter (with ac and dc inputs), a battery and battery charger. Alternately, some critical loads may be supplied directly from the battery.

A grounding and lightning protection system is provided. These systems conform to the requirements of IEEE and NFPA.

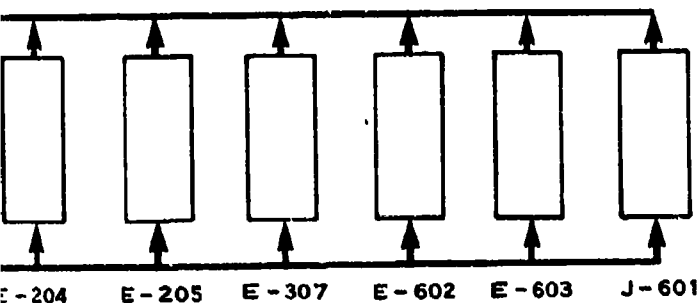
### 6.6.2 Cooling Water System

The cooling water system disposes of heat rejected from the coal gasifiers and from various points in the Gas Processing and Thermal Management systems. Referring to Figure 6.6-1, heat is transferred to the cooling water in shell and tube heat exchangers and carried to the cooling tower where it is rejected to the atmosphere. The total cooling load is estimated at 47 million Btu/hr.

Cooling loads for individual users are listed in Table 6.6-1:



E - 201 PRIMARY COOLER HEAT EXCHANGER  
 E - 202 GAS COMPRESSOR 1<sup>ST</sup> STAGE INTERCOOLER  
 E - 203 GAS COMPRESSOR 2<sup>ND</sup> STAGE INTERCOOLER  
 E - 204 GAS COMPRESSOR 3<sup>RD</sup> STAGE INTERCOOLER  
 E - 205 AMMONIA SCRUBBER COOLER  
 E - 307 CO SHIFT TRIM COOLER  
 E - 602 AIR COMPRESSOR INTERCOOLER  
 E - 603 STEAM CONDENSER  
 J - 601 STEAM JET AIR EJECTOR CONDENSER  
 L - 601 COOLING TOWER  
 P - 607 COOLING WATER PUMP  
 P - 608 GASIFIER COOLING WATER PUMP  
 R - 101 GASIFIERS  
 S - 603 OVERFLOW TANK



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**COAL GAS / FUEL CELL / COGENERATION**  
**WASHINGTON D.C. SITE**  
**PROCESS FLOW DIAGRAM**  
**COOLING WATER SYSTEM**  
**FIGURE 6.6-1**  
**EBASCO SERVICES INCORPORATED**

TABLE 6.6-1  
COOLING WATER SYSTEM LOADS

<u>Equipment</u>	<u>Designation</u>	<u>Heat Load (10<sup>6</sup> Btu/hr)</u>
<u>Coal Gasification</u>		
Coal Gasifiers	R-101	2.3
<u>Gas Cooling Cleaning and Compression</u>		
Primary Cooler Heat Exchanger	E-201	11.82
Gas Compressor 1st Stage Intercooler	E-202	4.59
Gas Compressor 2nd Stage Intercooler	E-203	3.25
Gas Compressor 3rd Stage	E-204	2.86
Ammonia Scrubber Cooler	E-205	.18
<u>CO Shift</u>		
Trim Cooler	E-307	.50
<u>Thermal Management</u>		
Air Compressor Intercooler	E-602	3.20
Steam Turbine Condenser	E-603	16.90
SJAE Condenser	E-604	.18
Miscellaneous Coolers		1.22

Major components of the cooling water system are the cooling tower, the cooling water pumps and the water supply and return piping.

The cooling tower is of the crossflow, mechanical draft type and provides 85°F cooling water at 8°F wet bulb approach and 20°F range. Air flow through the tower is maintained by axial flow fans with a total power requirement of approximately 100 HP.

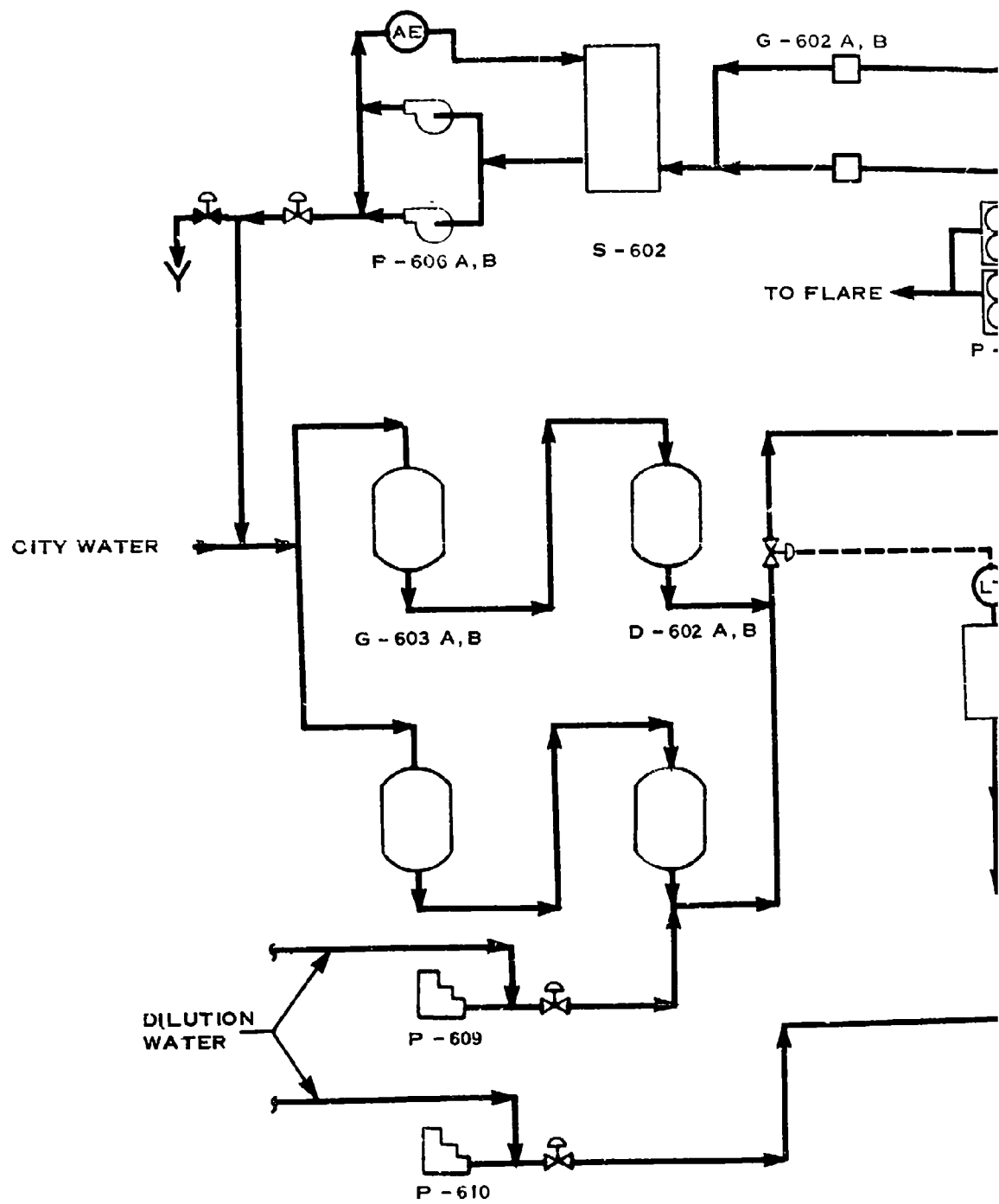
Two 100% capacity cooling water pumps are provided to circulate cooling water through the system. Each pump can deliver approximately 5000 gpm of cooling water at 80 feet total head and is driven by a 150 HP electric motor.

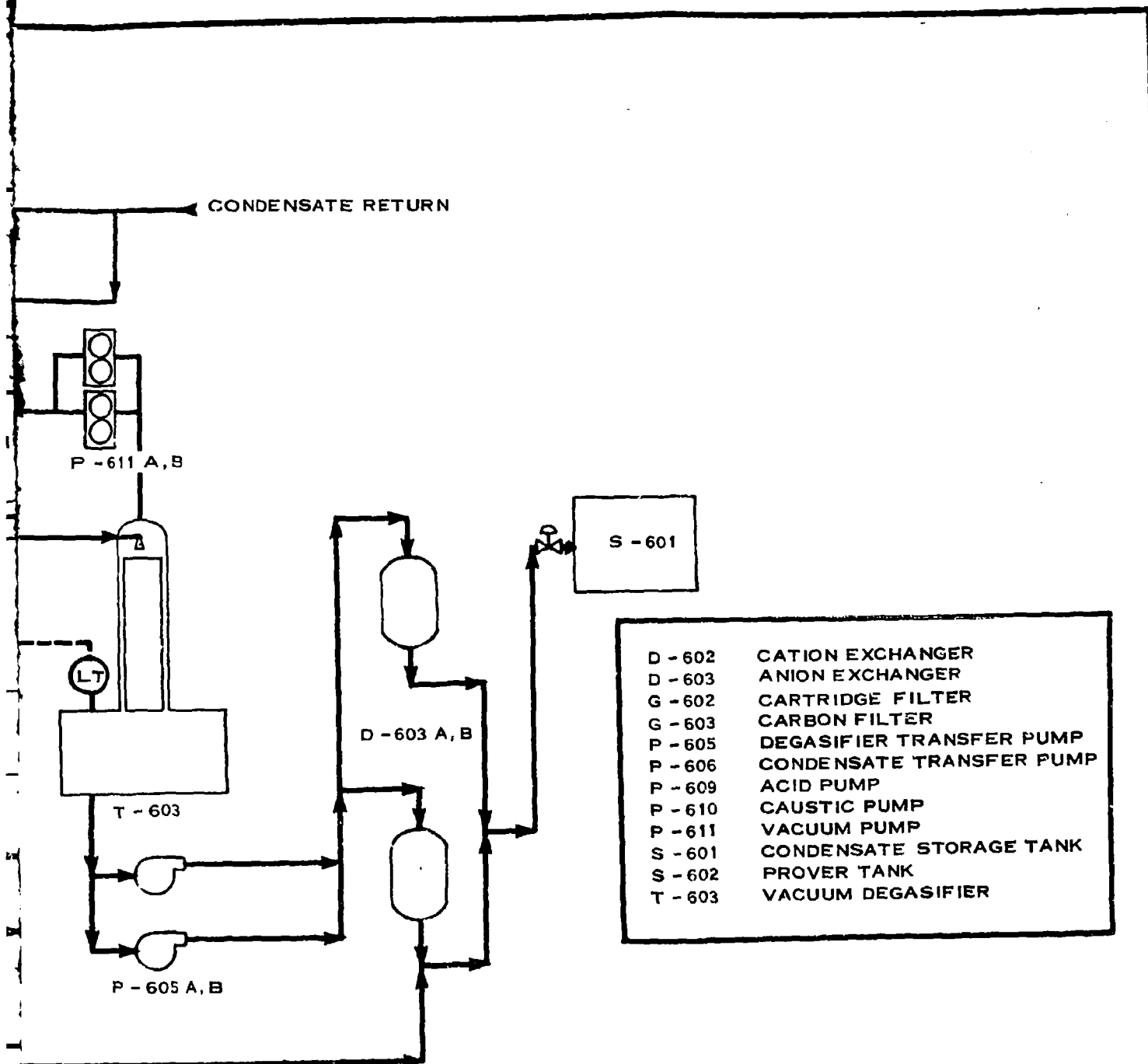
### 6.6.3 Water Treatment

The Makeup Water Treatment System shown in Figure 6.6-2 will produce a net to service flow of  $6.6 \times 10^5$  lbs per day of demineralized water based on processing either 100% city water or a mixture of city water and condensate from the Condensate Reclaim System. System design is based on processing 100% city water to meet the makeup water quantity and quality requirements of the fuel cell thermal management system. The expected city water analysis and fuel cell water quality requirements are shown on Table 6.6-2.

Makeup Water Treatment System consists of two (2) activated carbon filters, G-603 A&B to remove residual chlorine from the city water, to protect the anion ion exchange resin; two (2) Cation Exchangers, (D-602 A&B); a vacuum degasifier (T-603) with 100% redundant vacuum pumps, VP 601 A&B, and transfer pumps, P605 A&B, to remove dissolved gases such as  $\text{CO}_2$  and  $\text{O}_2$  from the city water and  $\text{CO}_2$ ,  $\text{H}_2\text{S}$  and  $\text{HCN}$  from the reclaimed condensate; two (2) Anion Exchangers, (D-603 A&B); a regeneration system, water quality analyzer and a control panel. The system is designed for A or B train to run for 12 hours and produce  $4.2 \times 10^5$  lbs of demineralized water total. The idle train will then be put into service when the operating train is regenerated. The system is designed for automatic operation and to permit the use of vessels from either train or both trains simultaneously. The design of this regeneration system includes waste neutralization prior to discharge.

The Condensate Reclaim System shown in Figure 6.6-2 filters collects and tests condensate for quality prior to transfer to the inlet of the makeup demineralizer. It is anticipated that the condensate return from the gasifier process will be suitable for reuse in Fuel Cell thermal management cycle. However, to prevent the introduction of excessive dissolved or suspended contaminants the condensate will be filtered through a 10 micron cartridge filter (G 602 A&B) and collected in Condensate Prover Tank, D-602, where it will be analyzed and transferred to the inlet of the Makeup Water Treatment System if it is of acceptable quality. Off standard quality condensate will be sent to the waste treatment system.





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**COAL GAS/FUEL CELL/COGENERATION**

**WASHINGTON D.C. SITE**

**FUEL CELL**

**WATER TREATMENT SYSTEM**

**FIGURE 6.6-2**

**EBASCO SERVICES INCORPORATED**

TABLE 6.6-2

Fuel Cell Makeup Water

Identification: A - Washington DC City Water (Sampled 3/15/85)

B - Fuel Cell Water Quality Requirements

<u>Constituent</u>		<u>PPM as</u>	<u>A</u>	<u>B</u>
Calcium	(Ca <sup>**</sup> )	CaCO <sub>3</sub>	79	
Magnesium	(Mg <sup>**</sup> )	CaCO <sub>3</sub>	23	
Sodium*	(Na <sup>*</sup> )	CaCO <sub>3</sub>	22.8	
Hydrogen = FMA	(H <sup>*</sup> )	CaCO <sub>3</sub>	0	
		CaCO <sub>3</sub>		
Total Cations		CaCO <sub>3</sub>	124.8	
Bicarbonate	(HCO <sub>3</sub> )	CaCO <sub>3</sub>	54.0	
Carborate	(CO <sub>3</sub> )	CaCO <sub>3</sub>	0	
Hydroxide	(OH <sup>-</sup> )	CaCO <sub>3</sub>	0	
Chloride	(Cl <sup>-</sup> )	CaCO <sub>3</sub>	28.2	
Sulfate	(SO <sub>4</sub> )	CaCO <sub>3</sub>	46.6	
Total Anions		CaCO <sub>3</sub>	124.8	
Conductivity		Micromho	269	10.0
Suspended Solids			-	1.0
		Fe		
Carbon Dioxide, Free*		CO <sub>2</sub>	2.7	0
Silica		SiO <sub>2</sub>	8.0	0.3
pH			7.6	5-7
Total Hardness gr/gal as CaCO <sub>3</sub>			5.96	0

#### 6.6.4 Plant Safety

The design of this facility incorporates features required to assure safety of personnel and equipment in the event of an unlikely major leakage of coal gas which is piped at pressures up to 152 psig. The constituents of this coal gas which would be of concern are the hydrogen and the carbon monoxide. The concentration of these components varies through the process from 17 to 32% for hydrogen and from 1 to 24% for carbon monoxide.

This type of process is normally located out-of-doors at grade level or in light weight, well ventilated structures, effectively reducing the consequences of gas leakage and simplifying its detection and control. Due to local aesthetic and area utilization constraints, this facility has the base floor level for the gasification and fuel cell areas 36 ft below grade with an open roof and gratings at intermediate levels, which in effect places the portions of the process containing coal gas out-of-doors. Supporting systems that do not contain coal gas or hydrogen are located south of the fuel cells and below a parking garage with a recreational area at grade level. (See Section 3.0 for further detail).

As presently conceived, this facility has several occupancies: a process area with gaseous hydrogen systems, a parking garage, and a place of public assembly. It is intended to adequately separate the occupancies in order to satisfy the criteria of governing codes and regulations.

Some of the criteria include:

- OSHA - Requirements for Safe Work places
- NFPA 101 - Life Safety Code
- NFPA 50A - Gaseous Hydrogen Systems
- NFPA 88A - Parking Structures

- NFPA 54 - National Fuel Gas Code (Reference)
- NFPA 496 - Purged and Pressurized Enclosures for Electrical Equipment in Hazardous Locations
- NFPA 70 - National Electrical Code
- NFPA - Standards pertaining to detection, suppression and alarm systems

Additional criteria may have to be addressed to satisfy such authorities having jurisdiction as the D.C. Fire Marshal, Chief Fire Inspector, Buildings Department and Chief Inspector, Zoning Board, and involved insurance carriers.

As a part of detailed engineering, it will be necessary to incorporate separation of the gas process area from parking and public assembly areas, ventilation, personnel egress, emergency power, explosion venting for any enclosures of gas bearing equipment or piping, fire and leak detection, fire suppression, personnel protection and adequate drainage.

#### - Structural Features

- Three hour fire rated separations between the process and parking occupancies and between the process and recreational occupancies. Penetrations must be sealed and fire-rated. Separate access and egress (enclosed stair towers, ramps, exits to outside) from each occupancy to beyond the facility.
- Where required, structure designed for blast resistance and explosion venting.

#### - Protection Systems

- Automatic water deluge systems for suppression of ordinary and flammable liquid fires and for reduction of heat, protection of personnel and minimization of facility damage in event of hazardous gas fires.

- Automatic hydrogen and carbon monoxide detection systems and alarms.
- Automatic smoke and/or flame sensing detection and alarm systems.
- Where applicable, ventilation system must maintain sufficient air flow in enclosed areas to limit potential gas concentrations to safe levels and air flow failure alarms. Ventilation for this purpose must be backed by an emergency power source.
- Adequate drainage and sump pump system for removal of automatic fire system discharge, manual hose discharge and process tank overflow or rupture discharge.
- All protection systems, including safety related ventilation equipment, must be status alarmed in the Control Room. Internal communications - both wireless and hardwired - must be provided for roving plant personnel.

#### 6.6.5 Nitrogen Gas Supply

Nitrogen gas is used to pressurize the fuel cell stacks during startup, to purge portions of the system during shutdown and to maintain a nitrogen blanket in certain gas processing equipment and the fuel cell stacks during layup. Shutdown of the fuel cell will cause an automatic nitrogen purge.

The system consists of an insulated liquid nitrogen storage tank with approximate dimensions of 7' diameter by 15' high with a capacity of 4000 gallons. The tank is of a standard cryogenic design equipped for truck refill by a commercial supplier. The liquid nitrogen is vaporized by an air heat exchanger for gas delivery to the system. Gas delivery is initiated by a remote manual signal from the control room, and automatically controlled by pressure and flow control valves.

The system is designed to deliver 1000 scfm of nitrogen at 375 psig, and is sized for four complete plant startup/shutdown cycles.

#### 6.6.6 Hydrogen Gas Supply

Hydrogen is needed by the fuel cell during startup and for passivation of the fuel cells during shutdown. On shutdown the fuel cell stacks are automatically passivated with pure hydrogen, and then purged with nitrogen. Passivation of the cell stacks corrects any local electrode polarization that has occurred due to gas impurities and prolongs the effective life of the cell stacks.

The system consists of truck delivered gas cylinders, containing a total of 250 pounds of hydrogen with an automatic pressure and flow control manifold. The system is designed to deliver 75 lb/hr of hydrogen at 375 psig, and it is sized for four startup/shutdown cycles.

#### 6.6.7 Station and Instrument Air

Clean, dry pressurized air is provided to the fuel cell cathode for passivation, to the fuel cell/cathode air compressor for startup and to

all pneumatic instruments. The system consists of a 200 scfm air compressor, dryer and a 500 ft<sup>3</sup> air receiver. Delivery pressure is 125 psig.

The system is sized for an 8000 scfm flow for 30 seconds during start-up.

## 6.7 SYSTEM CONTROL (I&C)

### 6.7.1 Introduction

The instrumentation and control system is configured with centralized control room and control processors. The input/output hardware is distributed functionally and geographically with the process being controlled, the input/output cards being separated from the controllers/processors so that signal wiring and cable maybe reduced by multiplexing. Each major process has a local subsystem control board located close to the process with sufficient displays and controls to operate the process independently of the Control Room.

This configuration conforms to current state-of-art control and instrumentation practice and results in the reduction in signal wires and cable and related construction costs.

Each sensor, transducer and instrument selected is to be the most reliable for the particular application and from a reputable supplier with an extensive service organization. Although different suppliers may be required to furnish the best instrumentation available, only one supplier furnishes the control hardware. This approach reduces the number of spare parts and maintenance training requirements, simplifies system design and consolidates contractual responsibility.

### 6.7.2 Control System Configuration

The control system is shown functionally in Figure 6.7-1. This includes a plant system processor and controller for each subsystem process. The plant system processor directs and monitors operation of subsystem controllers, providing the logic and sequencing for startup, operation and shutdown.

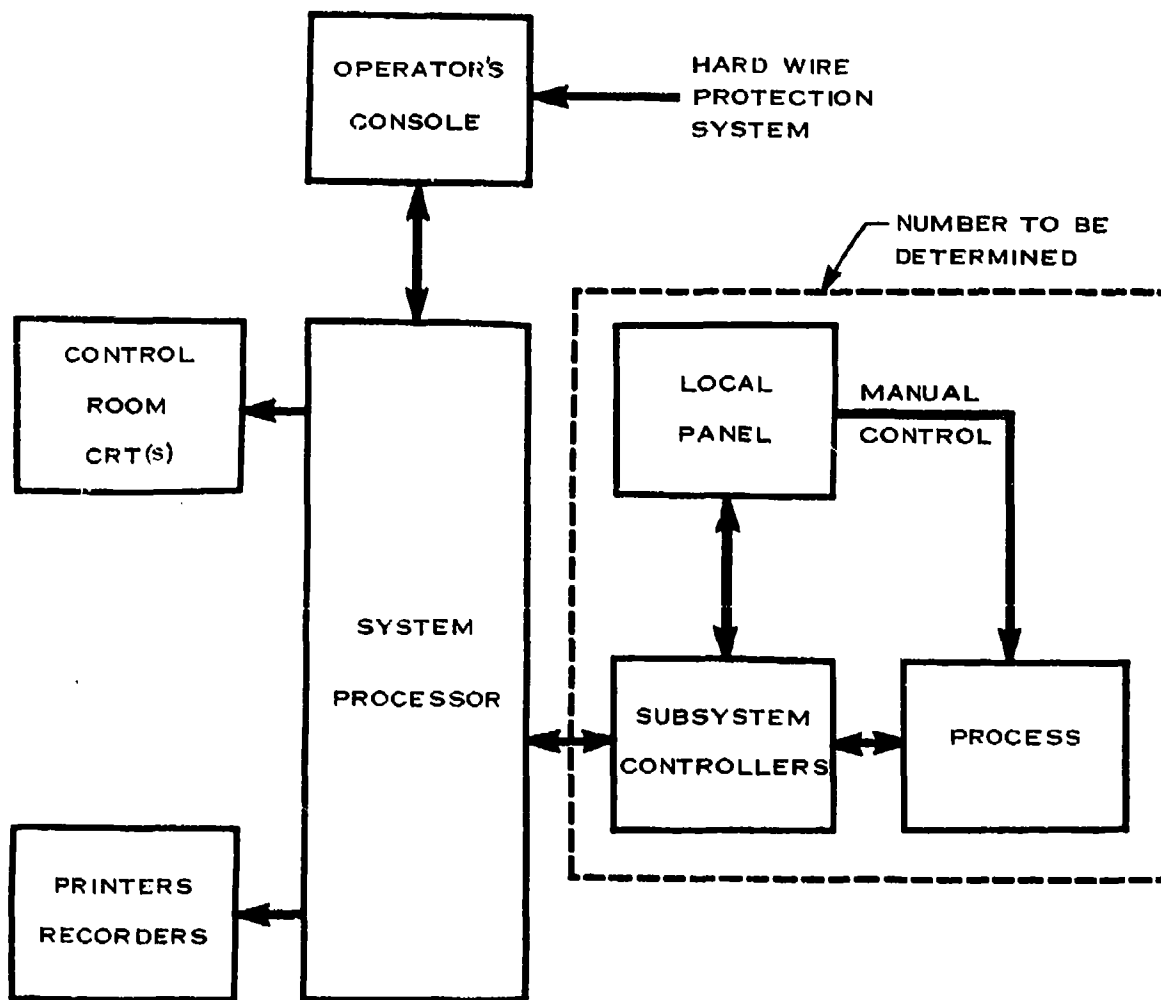


FIGURE 6.7 - 1 CONTROL SYSTEM FUNCTIONAL BLOCK DIAGRAM

The system may be operated from the control room console or from the local subsystem control panels.

The control room contains printers, recorders, CRT's and the operator's control console.

#### 6.7.3 Control Room Layout

The operator interface/peripherals are shown in Figure 6.7-2 and the control room operator's board layout is shown in 6.7-3. The operators console provides for the overall operating mode and power level control in addition to providing dedicated display plant alarms and important process parameters (temperature, pressure, flow, etc).

A separate central analysis console provided for engineering analysis of the process contains a CRT and keyboard to interface with a controller/computer for system analysis. This console is independent of the Control Room operator's console and the local process control boards so that system analysis and performance will not interfere with plant operation.

#### 6.7.4 Control Components and Operation

The system processor (see Figure 6.7-1) is the functional interface with the subsystem controller, furnishing the logic and sequence signals to control the entire plant. Each subsystem, has a controller with local control panel and displays.

There are four color graphic CRT's in the Control Room. One CRT is dedicated to each of the three major processes and the fourth is used for listing alarms and sequence of events during a system malfunction.

One printer is dedicated to preparation of operating and EPA required reports. The second is an alarm logger that tags the alarmed function initially and when it returns to normal.

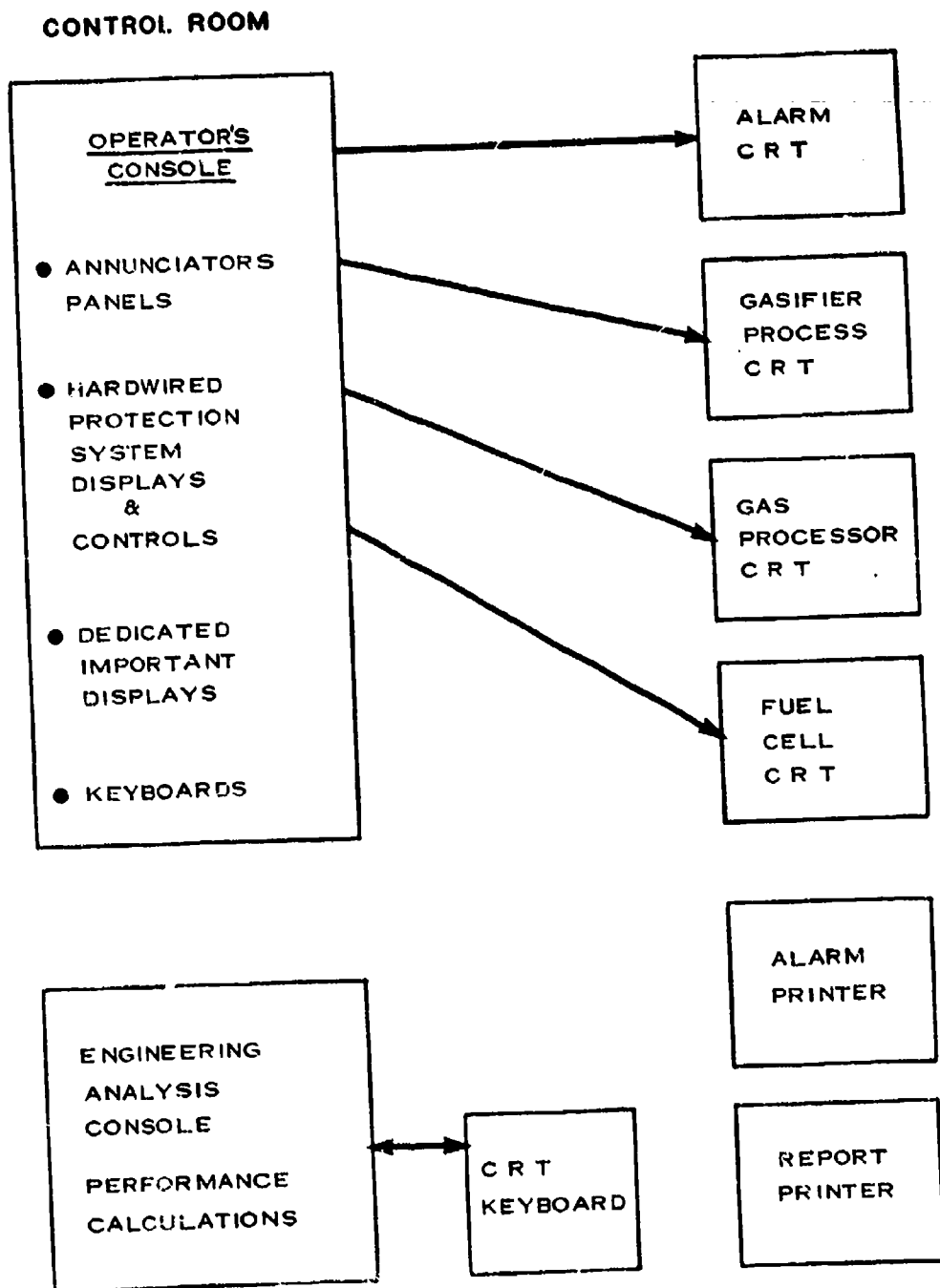


FIGURE 6.7 -2 OPERATOR INTERFACE AND PERIPHERALS

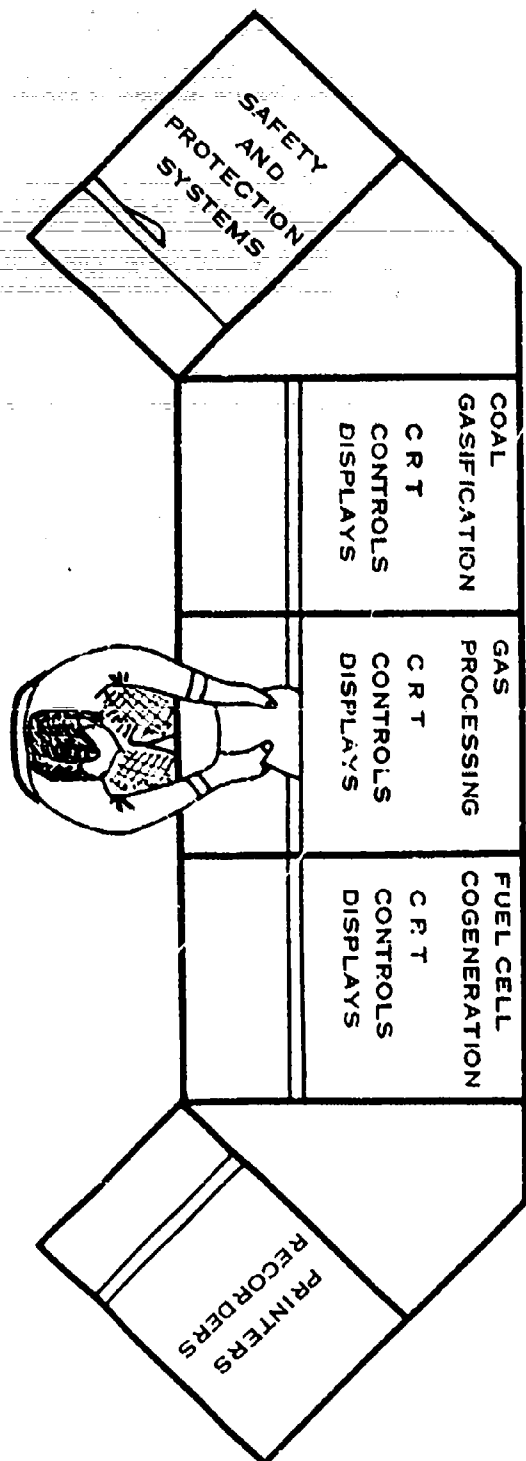


FIGURE 6.7-3 CONTROL ROOM OPERATOR'S BOARD

The process CRT's are color graphic with independent processor, memory and keyboard to format multiple page displays independently of the process controllers. This permits almost instant retrieval of any page without overloading the process controllers, increasing to a point response time.

The control console is in five sections with keyboards, manual controls, dedicated displays, CRT's and annunciator windows. Dedicated displays and manual controls are primarily for the hardwired protection system permitting the operator to override the processors in a major plant upset or component failure. If a failure occurs in the system processor, the plant may continue to operate through local control with subsystem controllers. If a failure occurs in the subsystem controller, there are sufficient manual controls and displays on each local control panel for manual control of the process.

Controls and displays are also included for certain off line ancillaries that are not part of any process subsystem. There is an auxiliary panel in the Control Room for power conditioning and distribution. In addition, there are local auxiliary control panels for material handling (coal and ash), fire protection, and water treatment. A preliminary layout of the control room indicates that approximately 1200 square feet are required for the Control Room and the attached Electronics Room. Supporting facilities, offices, store room, conference room, etc., are not included in this estimate.

#### 6.7.5 Safety

A complete system for monitoring and detection of safety conditions throughout the plant is provided. Conditions including fire, smoke, gas concentration and malfunctions in safety related systems are indicated and annunciated in the Control Room (refer to paragraph 6.6.4). Audio alarms are located as required throughout the plant.

## 6.7.6 System Control Description

### 6.7.6.1 Coal Gasification

#### a. Firebed and Ash Zones

Immediately above the ash bed is the combustion (firebed) zone. In the lower part of the firebed, carbon dioxide is formed from carbon in the fuel and the oxygen in the air/steam blast. Further up, the carbon dioxide combines with carbon and is converted into carbon monoxide. The delivery of the correct quantity of gas with uniform quality is ensured by maintaining these various zones at the proper level and thickness and by a suitable air/steam supply.

The above information on the fire and ash bed is determined by insertion of a steel rod. The dark end of the withdrawn rod indicates the ash depth; the portion of the rod glowing red, indicates the combustion zone; the next darker color indicates the reduction zone. These checks are performed every four to eight hours.

Depth of the fire bed is normally between 4 and 8 inches and the ash bed, between 12 and 20 inches. If ash bed depth is greater than desired, grate rotation speed is manually increased. Too great a depth of ash can decrease gas production while too shallow a depth reduces grate insulation and protection of the grate from excessive temperatures.

#### b. Gas Pressure Control

Gas pressure control is the main loop since steam, coal and gasification rates depend on air supply. To prevent air inleakage, the system is maintained under positive pressure. The output of the gasifier is regulated by a recorder controller sensing pressure in the suction line

of the gas compressors. As producer gas fuel cell demand increases and line pressure decreases, the controller modulates the air control valve admitting more air to the grate, increasing the rate of gasification. The air flow is modulated to suit demand. E.g., if gas pressure increases, air flow is reduced to lower the gasification rate.

#### c. Blast Saturation Temperature

Process water is evaporated into the air supply to control the fire bed temperature at a level where gasifier operation is optimized and the ash is prevented from clinkering. The water vapor content of supply air is controlled through a jacket water temperature controller. By modulating a valve in the jacket water circuit, temperature and therefore evaporation rate is maintained at the setpoint. The setpoint may be manually adjusted to maintain optimum firebed conditions.

#### d. Fuel Feed Level Control

The fuel feed to the gasifier is automatically controlled by a level detector in the upper bin to maintain its setpoint regardless of load change. As fuel is consumed a limit switch actuates the lockhopper valve through a motor operator located under the bin. To fill the lower bin, the bottom valves are closed and the upper valves opened, allowing coal to flow by gravity into the lockhopper. When the lockhopper is filled, usually in a matter of a few minutes, the upper valves close and lower valves open.

#### e. Grate Rotation

The rotational speed of the gasifier grate is automatically maintained at a point that is manually reset as required to maintain the correct depth of ash, and a safe firebed position.

The grate operates under the control of a timer mechanism consisting of a manually adjustable controller that controls the frequency that oil is admitted to hydraulic through a solenoid valve.

#### f. Flare Systems

Gasifier output normally matches fuel cell requirements. However, automatic flare systems are provided to burn excess gas which may be produced under off-normal conditions.

These flare systems include a pilot burner with automatic start and shutdown.

The flare is used during startup before the system has been fully purged and pressurized and also while any tests are performed with the gasification system.

Equipment failure is one event which results in excess gas being generated. The gas is flared until the gasifier throughput has been reduced to the appropriate level. In the event of power failure, the gasification system is automatically shutdown as a fail-safe operation with the gas being flared.

The flare is also used to burn any excess fuel gas generated during fuel cell load reduction.

#### 6.7.6.2 Gas Cooling, Cleaning and Compression

##### a. Anti-Surge Control for Centrifugal Compressors

The differential pressure between the suction and discharge line of the compressor is monitored in conjunction with a discharge line flow controller. The discharge line is defined as downstream of the third stage K.O. drum. A signal generated by differential pressure divided by flow will either open or close a flow control valve to send fuel gas from the discharge line back to the suction line through a bypass line.

#### b. Ammonium Sulfate Recovery

The ammonium sulfate saturator is controlled by liquid level and temperature. The quantity of sulfuric acid to the tower is controlled by level. Temperature setpoint error in the tower is cascaded to a flow control loop to control flow upstream of the ammonia scrubber exchanger by modulating the valve on the wash liquid line. A manually adjustable controller maintains flow of the ammonium sulfate from the tower at constant rate.

#### c. Tar Removal and Recovery

The principal control loops are based on level control. Tar pump operation is controlled by a tar collection tank liquid level controller. The tar separator is liquid level controlled for both tar and scrubbing water. In the event the scrubbing water level goes above the preset high liquid level, the blowdown stream will increase.

In addition, the liquor collection tank is level controlled tied to the discharge from the primary cooler pump after the split flow line. The primary cooler is liquid level controlled tied into the discharge from the primary cooler pump and flow controller recorder on the inlet of the scrubbing liquor feed to the tower. In the event the liquid level rises above the high limit the pump will blow down the excess through a by-pass line.

#### d. CO Shift

The principal control philosophy for the CO shift section is based on maintaining the required temperature and steam to gas ratio inlet to the CO shift reactors. This is accomplished by temperature measurement in the top section of both reactors transmitting signals to the control system to position the valves on the bypass lines around the feed/effluent heat exchanger II and CO shift steam generator. The proper steam to gas ratio to the first CO shift reactor is maintained by flow

control of the combined steam line from the CO shift steam generator and import steam line, by modulating the flow control valve on the steam import line. Both reactors will have temperature alarms in the top section of the catalyst bed and analyzer recorder alarms in the exit lines of the reactors to monitor CO concentration and steam to gas ratios.

Both the K.O. drum and trim cooler K.O. drum, are level controlled.

The fuel cell feed heater has a bypass line on temperature control for the fuel gas stream based on a temperature of the COS hydrolysis reactor.

#### e. Sulfur Removal and Recovery

The principal control loops and instrumentation for the Sulfur Removal and Recovery section are:

- The proper liquid to gas ratio is maintained in the venturi contactor by control of liquid level at the bottom of the vessel in conjunction with a level control valve on the line from the solution heater to the top of the reactor and a flow controller on the line to the venturi scrubber.
- The slurry decanter is level controlled and temperature control is maintained on the steam condensate line to ensure the flow of molten sulfur.
- The zinc oxide beds are flow controlled such that before hydrogen sulfide breakthrough occurs in the first drum there is interchange of flow between the first and second vessel. Both reactors have analyzer recorder alarms for monitoring hydrogen sulfide concentration levels.

- Exiting the zinc oxide vessels, the fuel gas flow to the fuel cells is pressure controlled. In the event there is an increase in line pressure, the control system will send a split signal to: (1) a control valve to open, thereby releasing the fuel gas to a common flare connected with the gasifier and (2) the suction line of the gas compressors pressure control system which in turn sends a signal to the air blower to maintain the required air flow to the gasifier thereby decreasing the gasification rate.

In the event line pressure decreases the PRC performs the function of increasing the air flow rate thereby increasing fuel gas production.

#### 6.7.6.3 Fuel Cell

The fuel cell system is designed for semi-automatic operation, requiring no operators in addition to those assigned to the Gas Processing Section. The fuel cell system is controlled by micro-processor based controllers that allow the operator to select the operating mode of the plant, and both the real and reactive power. The control system also automatically shuts the plant down during certain upset conditions.

During operation the power conditioner control automatically maintains the desired AC power level. The fuel cell controllers respond to the power demand of the power conditioning system by maintaining the appropriate DC current output. DC current is the prime parameter which controls the setpoints for the remainder of the system. Anode and cathode flow valves are controlled by DC current. The fuel cell controllers also monitor and control certain portions of the other systems to insure proper operation of the fuel cell.

In addition to manually selecting the AC power output, the operator can select any of the following operating modes:

- off
- standby
- load
- hold

In the off state, the fuel cells are maintained under a nitrogen blanket. In the standby mode a start-up sequence is activated. In this mode the cell stacks are pressurized with nitrogen, and various pumps and auxiliary systems are activated or their condition monitored. Using the electric start-up heaters in the Thermal Management System the fuel cell stacks are heated to 350°F. The fuel cells are passivated with hydrogen and the Gas Processing Section is activated such that fuel is flowing to the anode but no air is entering the cathode. On proceeding to load, air is admitted to the cathode and power is produced. When power and voltage exceed the minimum setpoint for the power conditioner, it is automatically activated and power is sent to the utility grid. On entering standby or shutdown mode, the cell stacks are automatically passivated with pure hydrogen from the hydrogen supply system, and the system is purged with nitrogen.

Certain off-standard conditions in the fuel cell system are alarmed and cause automatic shutdown. These include:

- Speed, surge condition, and bearing temperature of cathode air compressor.
- cathode exit temperature
- stack voltage
- hydrogen content in stack enclosure and in cathode exhaust
- oxygen content in anode exhaust
- cell cross pressure
- pallet current difference
- cell pressure
- stack coolant flow

This section reviews the emissions which will be generated by the Georgetown University GFC, discusses the applicable environmental laws and regulations and concludes that the GFC system as constituted requires no further emission control measures.

## 7.1

Summary of Emissions

Estimates of the air and water pollutants and solid wastes that will be emitted by the GFC are listed in Tables 7-2, 7-3 and 7-4.

For a comparison of GFC system emissions and discharges with regulatory limits, refer to Table 7-1. This table indicates that this project will be environmentally acceptable.

## 7.2

Applicable Laws and Regulations

This paragraph summarizes requirements of the applicable major environmental laws and regulations. Requirements for air, water and solid waste emissions, other federal and local environmental requirements, and compliance with National Environmental Policy Act are discussed in separate subparagraphs. Important environmental requirements are summarized in Table 7-6.

TABLE 7-1

GFC EMISSIONS VERSUS REGULATORY LIMITS

<u>Air</u>	<u>GFC Emission, (tons/year)</u>	<u>Regulatory Limit, (tons/year)</u>	
		<u>EPA(1)</u>	<u>DC</u>
NO <sub>x</sub>	34.2	40	
SO <sub>2</sub>	1.6 (of SO <sub>x</sub> )	40	(2)
CO	7.2	100	
Particulates	0.8	25	39.6
H <sub>2</sub> S	0.3	10	

<u>Water</u>	<u>GFC Emissions<sup>(3)</sup> (mg/l)</u>	<u>Regulatory Limit<sup>(4)</sup> (mg/l)</u>
COD	150	(5)
Phenol	0.3	20
Sulfur	Not Available	less than 10
pH	(6-8.5)(6) pH units	(6-8.5) pH units
Chlorine	less than 0.1	approx. 1
Metals	Not Available	Not Available(7)
Suspended Solids	20	less than 100
Ammonia	1	20

Solid Waste

Solid wastes determined to be hazardous will be managed according to requirements of the Resource Conservation and Recovery Act and local laws.

NoiseGFC EmissionDC Limit

55 dB at 100 feet

80 dB during construction and  
90 dB during operation, at the  
property line

TABLE 7-2  
ESTIMATED AIR EMISSIONS

	<u>Emission</u>	<u>Quantity (lb/day)</u>	<u>Source</u>
Coal Handling	Dust	Negligible	
Gasification(1)			Gasifier lock-hopper
	H <sub>2</sub>	2.0	
	CO <sub>2</sub>	17.5	
	C <sub>2</sub> H <sub>4</sub>	0.2	
	C <sub>2</sub> H <sub>6</sub>	0.3	
	N <sub>2</sub>	80.12	
	CH <sub>4</sub>	1.5	
	CO	39.2	
	H <sub>2</sub> S	0.8	
	COS	0.1	
	NH <sub>3</sub>	0.08	
	HCN	0.024	
	H <sub>2</sub> O	12.6	
Gas Processing	NO <sub>x</sub>	50.4	Ammonia Flare
	H <sub>2</sub> S	1.2	Stretford Oxidizer
Fuel Cell	NO <sub>x</sub>	137.4	Catalytic Combustor
	SO <sub>x</sub>	8.8	
	TSP	4.3	
	(Particulates)		
	Smoke	Negligible	
Thermal Management System (TMS)	None	-	

Notes:

1. Maximum possible emissions per day which could occur during the opening of the lockhopper valves during coal feeding.

TABLE 7-3  
ESTIMATED WATER EMISSIONS

	<u>Flow (GPD)</u>	<u>Emission</u>	<u>Concentration (mg/l)</u>	<u>Disposal</u>
Coal Processing	300	Not Available(1)	Not Available	Municipal Col- lection System
Gasification				
Treated Waste Water	10,000			
		COD	150	
		Phenol	0.3	
		NH <sub>3</sub>	1	
		Suspended Solids	20	
Sulfur Wash Water	7,200	Sulfur	Not Available	
Ash Sluice Water	300	Not Available		
Fuel Cell	None			
TMS				Municipal Col- lection System
Regen Wastes	10,000	Turbidity	20 NTU (6-8.5) pH units	
Boiler blow- down	4,180	Suspended Solids	20 (6-8.5) pH units	
Cooling Tower Blowdown	11,000	Chlorine	0.1 (6-8.5) pH units	

TABLE 7-4  
ESTIMATED SOLID WASTES

	<u>Solid Waste Quantity</u>	<u>Pollutant</u>	<u>Pollutant Quantity</u>	<u>Disposal</u>
Coal Handling	N/A(1)	Dust/Fines	NA	NA
Gasifier				
Ash	12.6 TPD	Trace elements including Be, B, CO, Cr, Cu, Ge, Mn, Ni, U and V.	NA	Carted away to landfill waste disposal
Cyclone Dust	2.4 TPD	Same trace elements as in ash	NA	Carted away to landfill or hazardous waste disposal
Spent Catalysts			NA	Carted away to landfill
CO shift	103 CF/Yr	Sulfur Compounds	NA	
COS Hydrolysis	3 CF/Yr	Sulfur Compounds	NA	
Purged Stretford solution	69 GPD	(2)	(2)	Carted away to hazardous waste disposal
ZnO From Gas Polishing	55 CF/Yr	ZnS	NA	Carted away to landfill
Wastewater Treatment Slurry	254 GPD	Heavy Metals	NA	Carted away to landfill or hazardous waste disposal
Fuel Cell	500 CF/Yr	Heavy Metals in spent catalyst and in replaced cell stacks	NA	Returned to manufacturer for recovery
TMS	None			

Notes:

1. NA - Not available
2. See Table 7-5.

TABLE 7-5  
COMPOSITION OF BLOWDOWN FROM STRETTFORD PROCESS(1)

<u>Constituent</u>	<u>Concentration (mg/l)</u>
NaHCO <sub>3</sub>	25,000
Na <sub>2</sub> CO <sub>3</sub>	5,200
NaVO <sub>3</sub>	6,600
Anthraquinone Disulfonic Acid	10,000
Iron	50
EDTA	2,700
Na <sub>2</sub> S <sub>2</sub> O <sub>3</sub>	120,000
NaCNS	90,000

Note:

1. Based on the complete conversion of HCN in gas feed to NaCNS; 2% conversion of H<sub>2</sub>S to Na<sub>2</sub>S<sub>2</sub>O<sub>3</sub>; and salt concentration of 25%.

TABLE 7-6

SUMMARY OF ENVIRONMENTAL REQUIREMENTS

Federal

National Environmental Policy Act processing

US Commission of Fine Arts building height review

Revision to EPA Form 1 on storm water discharges

Local

DC air permit

DC requirements and permit<sup>(1)</sup> for new discharges into DC's wastewater treatment plant

DC approval for any new tie-in into the DC sewer system

Regional Low Flow Agreement and Water Supply Emergency Plan for the Potomac River from Seneca Creek to Little Falls Dam

DC building permit

DC Board of Zoning Adjustment review

DC Noise Control Law requirements

Note:

1. Permit regulations are anticipated to be in place in 1986.

## 7.2.1 Air

### 7.2.1.1 Federal

A CAA Prevention of Significant Deterioration (PSD) permit is not required under the Federal Clean Air Act (CAA) because air pollutants are insufficient to activate the permit process<sup>(1)</sup>.

Under the PSD permit program, major sources and major modifications of such sources must have PSD permits before starting their construction. Major sources are defined as 1) specified kinds of sources (ie, fossil fuel boilers totalling more than 250 MMBTU/hr) which emit 100 tons/year or more of any CAA-regulated pollutant and 2) unspecified kinds of sources which emit 250 tons/year or more of any CAA regulated pollutant. The existing fluidized bed boiler (AFB) at GU could be considered a major PSD source because it emits over 250 tons/yr of  $\text{SO}_2$ . The GFC would not be considered a major modification to the AFB because it does not increase the emission rates above the threshold values listed in Table 7-7.

The GFC emitted pollutant which is closest to the PSD major modification level listed in Table 7-7 is  $\text{NO}_x$  at 34 tons/yr. The major modification level for  $\text{NO}_x$  emissions is 40 tons/yr.

Note that if any of the PSD major modification levels shown in Table 7-7 would be reached by the GFC, a PSD permit would still not be needed if compensating emission reductions could be accomplished at the AFB such that the net increase of the pollutant of concern (considering both emission decreases at the AFB and emission increases at the GFC) was less than the PSD major modification level.

The CAA also requires compliance with New Source Performance Standards (NSPS), which are technology-based air pollutant emission limits that EPA has established for specified source types. The only NSPS which apply to the project are those for "coal preparation plants". These NSPS, which will apply to the coal handling section of the GFC, will limit opacity to below 20 percent.

TABLE 7-7

THRESHOLD EMISSION LEVELS FOR MAJOR MODIFICATIONS  
UNDER THE CLEAN AIR ACT PSD PERMIT PROGRAM

<u>Pollutant</u>	<u>Emission Rate, tons/yr</u>
CO	100
NO <sub>x</sub>	40
SO <sub>2</sub>	40
Particulates	25
Ozone	40 of VOC's
Lead	0.6
Asbestos	0.007
Beryllium	0.0004
Mercury	0.1
Vinyl Chloride	1
Fluorides	3
Sulfuric Acid Mist	7
H <sub>2</sub> S	10
Total Reduced Sulfur (including H <sub>2</sub> S)	10
Reduced Sulfur Compounds (including H <sub>2</sub> S)	10

#### 7.2.1.2 District of Columbia

The District of Columbia Air Pollution Control Act of 1984 requires an air permit. This law requires compliance with the limitations in Table 7-8. According to DC government staff, this permit will not require air quality monitoring or modeling to determine compliance with the CAA National Ambient Air Quality Standards (maximum allowable ambient concentrations of such pollutants as SO<sub>x</sub>, NO<sub>x</sub> and particulates) because the project will not be a "major source"<sup>(2)</sup>. However, the DC government does have discretionary authority to impose monitoring/modeling on non-major sources.

#### 7.2.2 Water

##### 7.2.2.1 Federal

Although, an existing form must be amended to provide EPA with information on storm water discharges from the GFC plant, no federal permits are required.

Table 7-8

Applicable Requirements of the DC Air Pollution Control Act of 1984

Particulates

- o Fuel burning standard:

$$E = \frac{-0.23522}{.17455H}$$

Where E = allowable particulate emissions, lb /10<sup>6</sup>Btu

H = heat input, 10<sup>6</sup> Btu/hr

No combustion equipment may exceed 0.13 lb /10<sup>6</sup>Btu (The lowest limit any equipment may be required to meet is 0.02 lb/10<sup>6</sup> Btu)

- o Process standard: 0.03 grains/scf of dry exhaust gases
- o Fugitive dust emissions: Reasonable precautions must be taken to minimize these emissions. Such emissions are prohibited from material handling, screening, crushing, grinding, conveying, mixing, or other industrial type operation or process.

Sulfur

- o Fuel burning standard: Coal in excess of 1% sulfur by weight may not be burned unless the Mayor certifies that desulfurization results in SO<sub>x</sub> emissions no greater than the emissions normally resulting from the burning of coal with 1% sulfur.
- o Process limit: 0.05% by volume of SO<sub>x</sub> as SO<sub>2</sub>
- o The project may not add diluted air to the exhaust gas stream as a compliance method.

Table 7-8 (Cont'd)

Visible Emissions

- o Visible emissions may not be emitted except that discharges not exceeding 40% opacity (unaveraged) are permitted for 2 minutes in any 60 minute period and for an aggregate of 12 minutes in any 24 hour period during startup, cleaning, soot blowing, adjustment of combustion controls, and equipment malfunction.
- o Emission must be minimized at all times.
- o Where uncombined water is the only reason for failure to meet the visible emission requirements, the requirements will not apply.

Public Health and Welfare

- o Proposed equipment, facilities, and procedures must be adequate to minimize danger to public health and welfare.
- o The project must not be inimical to the public health and welfare.

#### 7.2.2.2 District of Columbia

Approval from DC will be required for the discharge of water effluents from the GFC into DC's sewer system, and ultimately into DC's Blue Plains Wastewater Treatment Plant. By sometime in 1986, this approval will be administered through a formal permit system pursuant to the DC Water Pollution Control Act of 1984. To receive this discharge approval, the GFC effluent must meet pretreatment standards which DC will establish on a case-by-case basis. Based on a telephone conversation with DC government staff<sup>(2)</sup>, the estimated concentrations of water pollutants in Table 7-3 are expected to be acceptable to DC. DC staff also made the following comments:

- o The COD level of 150 mg/l is probably acceptable.
- o The concentration of GFC sulfur effluent, which is currently unknown, should be kept under 10 mg/l.
- o The pH should be kept in the current 6 to 8.5 range.
- o Any metal pollutants may be required to meet the concentration criteria described in Reference 7-1.
- o The 0.3 mg/l concentration of phenol effluent which is equivalent to 0.03 lb of phenol/day, is acceptable. A phenol concentration of up to 10 mg/l, which would be equivalent to about 1 lb/day, would still probably be acceptable.
- o The suspended solids concentration of up to 20 mg/l is significantly below the estimated DC limit of 100 mg/l.
- o The project waste stream containing chlorine may have to be discharged separately into the DC sewer system from the waste stream containing phenols, in order to prevent the formation of chlorinated phenols.

DC approval will also be required if the project needs a new tie-in to the DC sewer system. According to DC, this approval can be promptly issued.

In addition, the use of water for the GFC plant must conform with the Regional Low Flow Agreement and Water Supply Emergency Plan for the Potomac River from Seneca Creek to Little Falls Dam. The Agreement and Plan limits the amount of water that can be withdrawn from the Potomac when river flow is very low due to drought.

### 7.2.3 Solid Waste

#### 7.2.3.1 Federal

As indicated in Tables 7-4 and 7-5, the GFC project will generate both non-hazardous and hazardous solid wastes.

The Resource Conservation and Recovery Act (RCRA) regulates the management of hazardous solid wastes and to some extent, the disposal of non-hazardous solid wastes<sup>(3)</sup>. EPA has delegated to DC the authority to regulate the RCRA hazardous solid waste provisions in the District. Therefore, the RCRA hazardous solid waste requirements applicable to the GFC project are discussed in subparagraph 7.2.3.2 below.

Note that some GFC plant solid wastes known to be hazardous may not be regulated as hazardous wastes under RCRA because they will not be determined to be hazardous by certain RCRA hazardous waste characteristic tests. These wastes will be regulated under the Comprehensive Environmental Response, Compensation, and Liability Act (the Superfund), which covers a larger number of hazardous wastes than RCRA. The Superfund basically regulates the cleanup of hazardous waste which is spilled or disposed of in an environmentally unacceptable manner. Due to this Superfund regulation, it is recommended that the GFC project owner ensure that the RCRA hazardous waste management standards be applied to the management of all hazardous wastes generated by the project, whether these wastes are regulated by RCRA or only by Superfund.

Pursuant to the RCRA non-hazardous solid waste provisions, the GFC non-hazardous solid waste should be disposed of in environmentally suitable solid waste disposal facilities.

#### 7.2.3.2 District of Columbia

As stated above, DC enforces the RCRA hazardous waste provisions which cover generation and transport of hazardous waste, hazardous waste treatment, storage, and disposal facilities.

The GFC owner has the following responsibilities under RCRA as a hazardous waste generator:

- o Obtain a hazardous waste generator ID number through the DC government, if GU's current ID number will not cover new project hazardous waste. (If GU's current ID number is sufficient, GU will still have to amend its hazardous waste generator notification form to account for any new hazardous waste.)
- o Ensure that the hazardous waste is stored on-site properly, ie so that no leakage occurs.
- o Correctly label the hazardous waste.
- o Ensure that all hazardous waste is transported off-site within 90 days of its generation.
- o Participate in the RCRA hazardous waste manifest system.

The GFC owner will not transport any hazardous waste off-site, but should ensure, through the RCRA hazardous waste manifest system, that the transporting of such waste complies with RCRA hazardous waste transport requirements.

The GFC project also will not be regulated as hazardous waste treatment storage, or disposal facility under RCRA. Generally, as indicated above, hazardous waste from the project will be transported off-site and then disposed of by contractors. However, the owner should ensure through the manifest system, that hazardous project wastes are disposed of in compliance with RCRA. It should be noted that 1984 amendments to RCRA require EPA to decide by July 1987 if the land disposal of hazardous wastes containing certain heavy metals should be banned. If such a ban is imposed, the disposal cost for certain hazardous GFC wastes could be more expensive than is currently anticipated.

The GFC project will treat hydrogen sulfide, which may be determined to be hazardous under RCRA. However, such treatment would not cause the GFC project to be regulated as a hazardous waste treatment facility because the RCRA regulations provide an exemption from such regulation for treatment which constitutes recycling. This exemption would apply to the hydrogen sulfide treatment since the treatment produces sulfur to be sold for recycling.

Other project wastes are planned to be recycled off-site. If these wastes are determined to be hazardous, they will be subject to new hazardous waste recycling regulations which EPA promulgated in January 1985<sup>(4)</sup> and which DC must adopt. The new regulations provide that the burning of hazardous waste for energy recovery may only take place in specified kinds of boilers and industrial furnaces. The new regulations also require that the management of other hazardous wastes which will be recycled are managed in conformance with the RCRA standards for hazardous waste generators, transporters, and storage facilities.

Non-hazardous solid waste from the GFC project also will be required to be managed in an environmentally safe manner according to the requirements of both DC and other nearby states where this waste may be disposed.

#### 7.2.4 Other Federal and Local Environmental Requirements

The project will need to obtain a variety of other approvals and comply with several other environmental requirements, some of which are highlighted below.

- o DC building permit - This permit can be obtained two to four months after submittal of the permit application. Permit issuance depends on approvals from several DC offices which regulate, for example, zoning (which includes height restrictions), erosion control, public works, and mechanical, electrical, and structural requirements.
- o DC Board of Zoning Adjustment - The board must review the project to ensure that it conforms with GU's master campus plan. This review could take three to four months.
- o DC Noise Control Law - This law limits noise to 80 dB(A) during construction and 90 dB(A) during operation, at the property line. (However, lower noise levels will be required to avoid adversely affecting the normal functioning of the university.)
- o US Commission of Fine Arts - The commission reviews building heights in the District.

#### 7.2.5 The National Environmental Policy Act (NEPA)

Pursuant to NEPA, federal agencies taking a "major federal action" which could affect the environment are required to conduct an environmental review of the action. As a result of this NEPA requirement, a NEPA review of the GFC project must be undertaken by DOA because of the involvement of DOA funds.

Based on conversations with EPA Region III staff<sup>(5)</sup>, it appears that NEPA review of the GFC project will not be required to include consideration of the remaining three sites of this program.

It is not certain that the NEPA review will require the preparation of an Environmental Impact Statement (EIS). However, an Environmental Assessment (EA), which is a relatively brief document describing anticipated environmental effects, will be required. The plant owner will prepare the EA, which will be reviewed, revised, and issued by DOA to interested parties and to government agencies for their review. Based on their comments, DOA will determine if environmental effects or public interest in the GFC project are sufficient to warrant preparation of an EIS.

It should take about two months to prepare an EA or an EIS. If only an EA is required, the NEPA review process should take six to eight weeks from receipt of GFC owner's EA document by DOA. If an EIS is required, the NEPA review process could take from 6 months to a year or longer.

NEPA requirements, as well as the DC air law (see Subsection 7.2.1.2) and other DC requirements, require that the project not jeopardize public health and safety. In addition to limiting environmental emissions, this means that public access to the facility must be restricted.

7.3 References

- 7-1 Code of Federal Regulations, Title 40, Part 52.21.
- 7-2 Personal communication with the District of Columbia Department of Consumer and Regulatory Affairs.
- 7-3 Code of Federal Regulations, Title 40, Parts 261 - 264.
- 7-4 Federal Register, Volume 50, Pages 613-668, January 4, 1985.
- 7-5 Personal communication with Environmental Management Branch, Environmental Protection Agency, Region III Regional Office.

## 8.0 APPENDICES

- A. Equipment List
- B. Forwarded References

APPENDIX A  
EQUIPMENT LIST

COAL HANDLING AND STORAGE SECTION

<u>Item No</u>	<u>Quantity</u>	<u>Description</u>
G-00i	1	Bag Type Dust Collector with (2) 100% Blowers C-001 A, B, each driven by 25 hp motor.
H-001	1	24" Belt Weighfeeder - 75 TPH, complete with adjustable flow gate, rate indicator, totalizer, dust hopper with scavenger screw, loading and discharge chute. Estimated hp = 15.
H-002	1	En-Masse Conveyor - 75 TPH, L type, horiz length = 20', vertical = 60', estimated hp = 40
H-003	1	En-Masse Conveyor, - 75 TPH, w/four discharge openings, length = 80', lift = 0', estimated hp = 15
H-008	1	En-Masse Conveyor, - 25 TPH, (3) Inlet Openings, and head end discharge, length 80', lift = 0', estimated hp = 5
H-009	1	En-Masse Conveyor - L Type, 25 TPH, 2 inlet openings, horizontal length = 30', lift = 70', estimated hp = 5
H-010	1	En-Masse Conveyor, 25 TPH, (2) inlet openings, (1) discharge opening, length = 20', lift = 3', estimated hp = 2
H-011	1	En-Masse Conveyor, 25 TPH, (1) inlet opening, (2) discharge openings, length = 70', lift = 0', estimated hp = 10

EQUIPMENT LIST

COAL HANDLING AND STORAGE SECTION (Cont'd)

<u>Item No</u>	<u>Quantity</u>	<u>Description</u>
H-012 A & B	2	24" Belt Weighfeeder, 0-25 TPH, variable speed, w/rate indicator, totalizer, and dust hopper, estimated HP = 7-1/2
H-013	1	Vibrating Screen, 25 TPH 1/4" opening, estimated HP = 10
P-001, A, B	2 (1 spare)	Sump Pump, 15 gpm, 30 ft head, 1/2 HP motor
S-001	1	Inground, steel, receiving hopper with 20 ft x 20 ft. Grizzly covered top x 27 ft high, installed beneath enclosed truck unloading station, equipped with dust control water spray nozzles.
S-002, A & B	2	Coal Storage Bunker, 27' x 27' square top x 69' high, 686T capacity
S-003	1	Fines Silo w/manually operated discharge gates, 20' Dia x 30' high

COAL GASIFICATION SECTION

R-101, A & B	2	Coal Gasification system including airblown, atmospheric pressure, single stage, 10' ID fixed-bed coal gasifier and cyclone dust collector (H-102 A & B)
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EQUIPMENT LIST

<u>Item No</u>	<u>Quantity</u>	<u>Description</u>
<u>GAS COOLING CLEANING AND COMPRESSION SECTION</u>		
C-201	1	Gas compressor - centrifugal, stainless steel, three stage w/inter cooling between stages, with a capacity of 13,200 SCFM and designed for 172 psia at 150°F, driven by 3338 hp electric motor. Including oil system, seal system and instrumentation.
D-201	1	Gas compressor 1st stage K.O. drum, - stainless steel, with mist eliminator designed for 31 psig at 150°F, 5'-8" diameter x 10'-6" high
D-202	1	Gas compressor 2nd stage K.O. drum, - stainless steel, with mist eliminator designed for 80 psig at 150°F, 4'-6" diameter x 8'-9" high
D-203	1	Gas compressor 3rd stage K.O. drum, - stainless steel, with mist eliminator designed for 157 psig at 150°F, 3'-8" diameter x 7'-6" high
D-204	1	Tar separator - coalescer plates installed in fabricated steel tank, 10'x 3' x 3' high with a capacity of 80 gpm.
E-201	1	Liquor cooler, - designed for $11.82 \times 10^6$ Btu/Hr duty, with 3437 ft <sup>2</sup> effective area, in carbon steel
E-202	1	Gas Compressor 1st stage intercooler, with stainless steel tubes and carbon steel shell, designed for a duty of $4.59 \times 10^6$ Btu/Hr duty, with 761 ft <sup>2</sup> effective area. Furnished with C-201
E-203	1	Gas Compressor 2nd stage intercooler, with stainless steel tubes and carbon steel shell, designed for $3.25 \times 10^6$ Btu/Hr duty, with 539 ft <sup>2</sup> effective area. Furnished with C-201

EQUIPMENT LIST (Cont'd)

GAS COOLING CLEANING AND COMPRESSION SECTION (Cont'd)

<u>Item No</u>	<u>Quantity</u>	<u>Description</u>
E-204	1	Gas Compressor 3rd stage cooler, with stainless steel tubes and carbon steel shell, designed for 2.86 x 10 <sup>6</sup> Btu/Hr duty, with 474 ft <sup>2</sup> effective area. Furnished with C-201
E-205	1	Ammonia scrubber cooler, with stainless steel tubes and carbon steel shell, designed for 180,000 Btu/Hr duty, with 110 ft <sup>2</sup> effective area
P-201 A, B	2 (1 Spare)	Saturator pump, - carbon steel centrifugal horizontal, rated for 191 gpm at 80 ft, driven by 7.5 hp electric motor
P-202 A, B	2 (1 Spare)	Tar pump-carbon steel gear type, rated for 15 gpm and driven 1/3 hp electric motor
P-203 A, B	2 (1 Spare)	Liquor pump-carbon steel centrifugal horizontal rated for 88 gpm at 40 ft, driven by 1.5 hp electric motor
P-204 A, B	2 (1 Spare)	Primary cooler pump, stainless steel centrifugal horizontal rated for 2626 gpm at 120 ft, driven by 125 hp electric motor
P-205 A, B	2 (1 Spare)	Acid circulation pump, - stainless steel centrifugal horizontal, rated for 44 gpm at 50 ft, driven by 1.5 hp electric motor
S-201	1	Tar collection tank - 8 ton capacity vertical carbon steel tank designed for 30 psig at 205°F. 5' diameter x 14' high
S-202	1	Liquor collection tank - 3 ton capacity vertical carbon steel tank designed for 30 psig at 180°F. 3'-6" diameter x 10'-0 high

EQUIPMENT LIST (Cont'd)

GAS COOLING CLEANING AND COMPRESSION SECTION (Cont'd)

<u>Item No</u>	<u>Quantity</u>	<u>Description</u>
T-201	1	Saturator - direct contact spray tower, designed for 30 psig at 820°F, in carbon steel. 5'-3" diameter x 70'-0" high
T-202	1	Primary cooler - venturi type scrubber, designed for 30 psig at 200°F, in carbon steel with stainless steel internals. 8'-0" diameter x 21'-0" high
T-203	1	Ammonium sulfate saturator - stainless steel tower, designed for 173 psig at 150°F. 3'-6" diameter x 15'-0" high
U-201	1	Dispersed phase precipitator - wet electrostatic precipitator, designed for 19,950 ACFM, with 99% efficiency, 18.4KW, 26 KVA, carbon steel.

EQUIPMENT LIST (Cont'd)

CO SHIFT SECTION

<u>Item No</u>	<u>Quantity</u>	<u>Description</u>
D-301	1	K.O. Drum - stainless steel vessel designed for 150 psig at 260°F, with wire mesh separator. 3'-2" diameter x 6'-0" high
D-302	1	Trim Cooler K.O. Drum - stainless steel vessel designed for 145 psig at 150°F, with wire mesh separator. 3'-2" diameter x 6'-0" high
E-301	1	Feed/Effluent Heat Exchanger II - designed for $4.6 \times 10^6$ Btu/Hr duty with 356 ft <sup>2</sup> effective area. 1-1/4 Cr-1/2 MO tubes, stainless steel shell.
E-302	1	Feed/Effluent Heat Exchanger I - designed for $2.8 \times 10^6$ Btu/Hr duty with 228 ft <sup>2</sup> effective area. 1-1/4 Cr - 1/2 MO tubes, stainless steel shell
E-303	1	CO Shift Steam Generator - Kettle type heat exchanger designed for $1.6 \times 10^6$ Btu/Hr duty with 264 ft <sup>2</sup> effective area. 1-1/4 Cr - 1/2 MO tubes, stainless steel shell
E-304	1	Fuel Cell Feed Preheater - stainless steel heat exchanger designed for $4.9 \times 10^6$ Btu/Hr duty with 890 ft <sup>2</sup> effective area
E-305	1	Feed Gas Preheater - stainless steel heat exchanger designed for $3.2 \times 10^6$ Btu/Hr duty with 1470 ft <sup>2</sup> effective area
E-306	1	Air Cooler - stainless steel, designed for $14.7 \times 10^6$ Btu/Hr duty with 4116 ft <sup>2</sup> effective area and 75 hp fan
E-307	1	Trim Cooler - designed for $0.5 \times 10^6$ Btu/Hr duty with 344 ft <sup>2</sup> effective area. Stainless steel tubes and carbon steel shell

## EQUIPMENT LIST (Cont'd)

### CO SHIFT SECTION (Cont'd)

<u>Item No</u>	<u>Quantity</u>	<u>Description</u>
F-301	1	Start-up Heater - fired heater, designed for $18 \times 10^6$ Btu/hr duty and used for start-up only
R-301	1	1st CO Shift Reactor - 1-1/4 Cr-1/2 MO converter, designed for 175 psig at 930°F. 4'-6' diameter x 14' - 0" high packed with 160 ft <sup>3</sup> sulfided shift catalyst
R-302	1	2nd CO Shift Reactor - 1-1/4 Cr-1/2 MO converter, designed for 175 psig at 610°F. 4'-6' diameter x 13' - 2" high, packed with 145 ft <sup>3</sup> sulfided shift catalyst

### SULFUR REMOVAL AND RECOVERY SECTION

D-402 A, B	2	ZnO Drum - carbon steel vessel designed for 125 psig at 425°F 13'-0" diameter x 18' - 6" high, packed with 1930 ft <sup>3</sup> ZnO absorbent
R-401	1	Hydrolysis Reactor - carbon steel vessel designed for 125 psig at 425°F,, 6'-0" diameter x 12' - 0" high, packed with 226 FT <sup>3</sup> COS hydrolysis catalyst
X-401	1	Stretford Sulfur Removal and Recovery Package, including:  C-401     Air blower D-401     Slurry decanter E-401     Solution heater H-401     Solid separation, wash and reslurry S-401     Oxidizer tank S-402     Balance tank S-403     Slurry tank T-401     Venturi contactor

Nominal sulfur capacity 2.4 STPD

### PROCESS CONDENSATE TREATMENT SECTION

G-501 A, B	2 (1 Spare)	Carbon Filter - carbon steel plate and frame filter press designed for 2300 gpd flow with 4.5% solids dewatered to 35% solids
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# EQUIPMENT LIST (Cont'd)

## PROCESS CONDENSATE TREATMENT SECTION (Cont'd)

<u>Item No</u>	<u>Quantity</u>	<u>Description</u>
E-501	1	Sour Water Heater - stainless steel heat exchanger, designed for 405,000 Btu/Hr duty with 40 ft <sup>2</sup> effective area
P-501 A, B	2 (1 spare)	Sour Water Pump - stainless steel centrifugal horizontal rated for 10 gpm at 120 ft and driven by 2 hp electric motor
P-502 A, B	2 (1 spare)	Waste Water Pump - stainless steel centrifugal horizontal, rated for 12 gpm at 40 ft and driven by 1/2 hp electric motor
P-506 A, B	2 (1 spare)	Recycle Water Pump - carbon steel centrifugal horizontal, rated for 55 gpm at 40 ft and driven by 1.5 hp electric motor
S-501	1	Sour Water Storage - stainless steel horizontal tank designed 15 psig at 180°F 9'-0" diameter 9" - 0 high
T-501	1	Ammonia Stripper - carbon steel tower designed for 30 psig at 300°F. 2'-0" diameter x 30' - 0" high and packed with 2 inch ceramic intalox saddles.
X-501	1	Waste Water Treatment System - Powder Activated Carbon Treatment (PACT) package including:  C-501 Air blower H-501 Virgin carbon storage H-502 Polyelectrolyte storage P-503 Virgin carbon feed pump P-504 Polyelectrolyte feed pump S-502 Settling tank S-503 Aeration contact tank

# EQUIPMENT LIST (Cont'd)

## FUEL CELL SECTION

<u>Item No</u>	<u>Quantity</u>	<u>Description</u>
C-601	1	Two stage air compressor with inter-cooler. Gear driven by turboexpander. Complete with controlling instrumentation, seal and lubrication system. 15,319 scfm, at 3267 HP.
CC-601	1	Catalytic Combustor. Pressure vessel containing Pt/Pd catalyst on metalor ceramic matrix, complete with mixing manifold.
E-602	1	Intercooler heat exchanger for air compressor. $3.3 \times 10^6$ Btu/Hr duty with 200 gpm cooling water flow.
EG-601	1	Electric Generator, gear driven by turboexpander, 2.54 MW.
F-601	1	Air Filter for air compressor intake.
FC-601 A to R	18	Water cooled phosphoric acid fuel cell stacks by UTC. Pressure vessel 6' dia by 11' 6" high, containing 500 cells each of 10.6 ft <sup>2</sup> of active electrode surface. Vessels are skid mounted in groups of three along with prefabricated piping. Vessels complete with insulation, freeze protection heaters, and hydrogen leak detection instrumentation. Gross output of 18 stacks is 11.6 MWe DC.
GA-601	1	Station and Instrument Air. 200 SCFM compressor, with 500 ft <sup>3</sup> air reservoir. Delivery pressure 125 psig.
GH-601	1	Hydrogen gas supply system 250 lb of hydrogen stored in pressure cylinders with flow and pressure control. Delivery pressure 375 psig.
GN-601	1	Nitrogen gas supply system. Consisting of 7' diameter by 15' high liquid nitrogen storage tank, complete with vaporizing liquid/air heat exchanger and pressure/flow control. Delivery pressure 375 psig.

EQUIPMENT LIST (Cont'd)

FUEL CELL SECTION (Cont'd)

<u>Item No</u>	<u>Quantity</u>	<u>Description</u>
T-601	1	Turboexpander, shaft linked with air compressor, 7056 HP

POWER CONDITIONING SECTION

PC-601	1	11 MW power conditioning converted system including inverter bridges series reactors, dc switchgear
PC-602	1	Electrical Protection Unit
PC-603	1	Output transformer 3-winding, liquid-filled 11 MVA, 30, 13800/480V.
PC-604	1	15 kV class metal-clad breaker
PC-605	1	Auxiliary power transformer 2500 kVA, 13800/480V.
PC-606	1 Lot	Miscellaneous transformers 480/208/120V
PC-607	1 Lot	Power Panels
PC-608	1	480 V Motor Control Center

# EQUIPMENT LIST (Cont'd)

## THERMAL MANAGEMENT SECTION

<u>Item No</u>	<u>Quantity</u>	<u>Description</u>
B-601	1	Heat recovery steam generator, inlet gas - 124,921 lb/hr, 664 F, steam output - 9076 lb/hr, 240 psig, 397°F; economizer makeup - 40551 lb/hr, 100°F; 5% boiler blowdown; boiler surface, 4300 ft <sup>2</sup> (est.) economizer surface, 1800 ft <sup>2</sup> (est); design pressure/temperature: gas side 10 psig/1300 F, steam side 350 psig/450°F; 50°F pinch point temperature; 98% efficiency.
D-601	1	Deaerating heater, inlet water 40551 lb/h, 217°F; operating at 26 psia, 242°F; deaerating steam 1200.6 Btu/lb; 10 minute water storage capacity
E-601	1	Blowdown heat exchanger, stainless steel, 40 ft <sup>2</sup> area (est); hot side inlet water - 1451 lb/h, 397°F; cold side inlet water 3000 lb/h, 242°F; 10°F drains approach temperature
E-603	1	Steam Surface Condenser: Rated steam flow 19,000 lb/h, duty 16.9 x 10 <sup>6</sup> Btu/lb, 4" H <sub>2</sub> O; two-pass; stainless steel tubes, 1230 ft <sup>2</sup> , (est.) 15 ft long, 3/4 in diameter, 20 BWG; 85% cleanliness factor; cooling water 1690 gpm, 85°F, 20°F rise; 200 gal (min) hot well storage
EG-602	1	Electric generator, 1215 kW
J-601	1	Steam jet air ejector, two-stage, with inter-after condenser, 230 psia steam
P-601 A, B	2 (1 spare)	Fuel cell cooling water pump, 420 gpm 150 ft TDH, 25 hp motor, 3500 rpm, 300 lb rating, 316 stainless steel fitted parts
P-602 A, B	2 (1 spare)	Condensate Pump: 50 gpm, 150 ft TDH, 5 hp motor, stainless steel fitted

EQUIPMENT LIST (Cont'd)

THERMAL MANAGEMENT SECTION (Cont'd)

<u>Item No</u>	<u>Quantity</u>	<u>Description</u>
P-603 A, B	2 (1 spare)	Makeup Water Pump: 100 gpm, 250 ft TDH, 15 hp motor, stainless steel fitted
S-601	1	Condensate storage tank, 14,000 gal usable storage, 10 ft diameter x 24' high, lined carbon steel with rubber bladder.
T-602	1	Steam turbine, condensing type, multi-stage, 230 psia inlet pressure, 4" H <sub>2</sub> O exhaust pressure, 15.6 lb/kwh steam rate, 3600 rpm
U-601	1	Vent Stack, carbon steel, 36 in diameter 87 ft high, 80 ft/sec gas velocity, carbon steel.
P-604 A, B	2 (1 spare)	Feedwater pump; 100 gpm, 765' TDH, 40 hp motor, stainless steel fitted materials.

EQUIPMENT LIST (Cont'd)

COOLING WATER SECTION

<u>Item No</u>	<u>Quantity</u>	<u>Description</u>
L-601	1	Cooling Tower, Forced draft, cross-flow, 5000 gpm, 95°F outlet temperature, 8°F approach, 20°F range consisting of 4 cells each with a 25 HP motor driven fan. Overall dimensions 21 ft wide, 48 ft long, 13 ft high. Operating weight 93,000 lb.
P-607 A, B	2 (1 spare)	Cooling Water Pump, centrifugal, horizontal, 3000 gpm, 80 ft head, driven by a 150 HP motor. Materials: Bronze impeller, CI casing, stainless steel shaft. Dimensions: 42" wide, 43" high, 80" long. Operating Weight 4,100 lb.
F-608 A, B	2 (1 spare)	Gasifier Cooling Water Pumps, centrifugal, horizontal 90 gpm, 60 ft head, driven by a 3 HP motor. Materials: Bronze impeller, CI casing, stainless steel shaft. Dimensions: 12" wide, 20" high, 36" long. Operating Weight 370 lb
S-603	1	Gasifier Overflow Tank, carbon steel, 3 ft diameter, 4 ft high.

EQUIPMENT LIST (Cont'd)

WATER TREATMENT SYSTEM

<u>Item No</u>	<u>Quantity</u>	<u>Description</u>
D-602 A, B	2	Cation Exchanger: 4'0" diameter 10'-0" straight side with dished heads. Vessel - rubberlined carbon steel, PVC piping and internals Resin-Strong Acid Cation 6'0" bed depth - Countercurrent regeneration with blocking flow
D-603 A, B	2	Anion Exchanger: 4'0" diameter 12'-0" straight side with dished heads. Vessel - rubberlined carbon steel, PVC piping and internals Resin-Strong Acid Cation 6'0" bed depth - Countercurrent regeneration with blocking flow
G-602 A, B	2	Cartridge Filter - 10 micron cartridge filters, duplex arrangement PVC lined ductile iron housing. Quick disconnect cover for cartridge replacement. Inlet and outlet 2 inch flanged connections, 150 lb design
G-603 A, B	2	Carbon Filter - 3'0" diameter x 7' 6" straight side with dished heads. Vessel - coated carbon steel with PVC piping and internals. Activated Carbon - 3'-0" bed depth. Anthracite Subfill - 1'-5" bed depth
P-605 A, B	2 (1 spare)	Degasifier Transfer Pump - horizontal centrifugal type pump. Rated at 50 gpm and 100 ft TDH. 3 HP motor at 3600 rpm FRP casing and impeller
P-606 A, B	2 (1 spare)	Condensate Transfer Pump - horizontal centrifugal type pump. Rated at 25 gpm and 100 ft TDH. 3 HP motor at 1800 rpm
P-611 A, B	2 (1 spare)	Vacuum Pump Liquid Ring Vacuum Pump. 975 RPM pump speed with belt drive and 10 HP motor. Cast iron casing.

EQUIPMENT LIST (Cont'd)

WATER TREATMENT SYSTEM

<u>Item No</u>	<u>Quantity</u>	<u>Description</u>
S-602	1	Condensate Prover Tank 500 gal FRP tank with rubber bladder
T-603	1	Vacuum Degasifier: 2'-6" diameter 19'-0" straight tower with 250 gal clearwell. Vessel - coated carbon steel with PVC internals. Packing: Maspac FN-200 60 cu ft.

## APPENDIX B

### FORWARDED REFERENCES

Referenced materials are listed at the end of each chapter. Most of these references were submitted with the March 1985 Report CLIN 0001. New references are listed below and forwarded separately, except as noted.

<u>Reference No.</u>	<u>Title</u>
2-2	Fluor Power Services, Inc., "Component Failure and Repair Data for Coal-Fired Power Units", EPRI AP-2071, October 1981.
3-1	ANSI/IEEE C37.95-1973, Guide for Protective Relaying of Utility-Consumer Interconnections.
3-2, 6.4-4	Ebasco Report PRC-HVDC-001, High Voltage Direct Current (HVDC) Reliability Study, dated February 13, 1984.
3-3	IEEE 519-1981, Guide for Harmonic Control and Reactive Compensation of Static Power Converters.
3-4	Thos. F. Ellerbe/Mariani and Associates drawing No. S-1, entitled "Log of Soil Borings and General Structural Notes, Heating-Cooling Plant, Phase D", dated 7/3/63 (not forwarded).
6.4-3	ANSI C34.2-1968 (1973), Practices and Requirements for Semiconductor Power Rectifiers.
7-1	Code of Federal Regulations, Title 40, Part 52.21 (not forwarded).
7-3	Code of Federal Regulations, Title 40, Part 261-264 (not forwarded).
7-4	Federal Register, Volume, 50, Pages 613-668, January 4, 1985 (not forwarded).